San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

DOCKET
08-AFC-1
DATE NOV 04 2008
RECD. NOV 06 2008

NOV 04 2008

Christopher Meyer
Project Manager
California Energy Commission
1516 Ninth Street
Sacramento, CA 95814

Re: Notice of Final Determination of Compliance (FDOC)
Project Number: C-1080386 – Avenal Power Center LLC (08-AFC-01)

Dear Mr. Meyer:

The District mailed a letter, dated October 30, 2008, notifying you of the issuance of the Final Determination of Compliance for the Avenal Power Center LLC power plant. The letter was incorrectly titled "Notification of Preliminary Determination of Compliance (PDOC)". The title should have stated the letter was the "Notice of Final Determination of Compliance (FDOC)", consistent with the body of the letter. Please accept this letter as a correction to the previous notice letter dated October 30, 2008.

Thank you for your cooperation in this matter. If you have any questions, please contact Mr. Jim Swaney of the Permit Services Division at (559) 230-5900.

Sincerely,

David Warner
Director of Permit Services

DW:df

Enclosures

Mr. Christopher Meyer
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Thank you for your cooperation in this matter. If you have any questions, please contact Mr. Jim Swaney of the Permit Services Division at (559) 230-5900.

Sincerely,

David Warner
Director of Permit Services

DW:df

Enclosures

Fresno Bee

NOTICE OF FINAL DETERMINATION OF COMPLIANCE

NOTICE IS HEREBY GIVEN that the San Joaquin Valley Unified Air Pollution Control District has issued a Final Determination of Compliance (FDOC) to Avenal Power Center LLC for the installation of a nominal 600 MW combined cycle power plant, located at NE¼ Section 19, T21S, R18E – Mount Diablo Base Meridian on Assessor's Parcel Number 36-170-032 in Avenal, CA.

All comments received following the District's preliminary decision on this project were considered. Changes were made to the DOC in direct response to comments received from the oversight agencies and other interested parties. The changes made were minor and did not increase permitted emission levels or trigger additional public notification requirements.

The application review for project C-1080386 is available for public inspection at the **SAN JOAQUIN VALLEY UNIFIED AIR POLLUTION CONTROL DISTRICT, 1990 EAST GETTYSBURG AVENUE, FRESNO, CA 93726.**

FINAL DETERMINATION OF COMPLIANCE EVALUATION

Avenal Power Center Project
California Energy Commission
Application for Certification Docket #: 08-AFC-01

Facility Name:	Avenal Power Center, LLC
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Engineer:	Derek Fukuda, Air Quality Engineer
Lead Engineer:	Joven Refuerzo, Supervising Air Quality Engineer
Date:	October 28, 2008
Project #:	C-1080386
Application #'s:	C-3953-10-0, C-3953-11-0, C-3953-12-0, C-3953-13-0, and C-3953-14-0
Submitted:	February 29, 2008

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I. PROPOSAL:

Avenal Power Center, LLC is seeking approval from the San Joaquin Valley Air Pollution Control District (the "District") for the installation of a "merchant" electrical power generation facility (Avenal Energy Project). The Avenal Energy Project will be a combined-cycle power generation facility consisting of two natural gas-fired combustion turbine generators (CTGs) each with a heat recovery steam generator (HRSG) and a 564 MMBtu/hr duct burner. Also proposed are a 300 MW steam turbine, a 37.4 MMBtu/hr auxiliary boiler, a 288 hp diesel-fired emergency IC engine powering a water pump, a 860 hp natural gas-fired emergency IC engine powering a 550 kW generator and associated facilities. The plant will have a nominal rating of 600 MW.

During the 30-day public notice period for this project several comments were received by the District from various community and regulatory entities. These comments and the Districts responses can be seen in Attachments J, K, and L. Based on these comments, the only significant change to the DOC was the lowering of the CO emission factor for the two natural gas-fired CTG's from 4.0 ppmvd @ 15% O_2 to 2.0 ppmvd @ 15% O_2.

The Avenal Energy Project is subject to approval by the California Energy Commission (CEC). Pursuant to SJVAPCD Rule 2201, Section 5.8, the Determination of Compliance (DOC) review is functionally equivalent to an Authority to Construct (ATC) review. The Determination of Compliance (DOC) will be issued and submitted to the CEC contingent upon SJVAPCD approval of the project.

The California Energy Commission (CEC) is the lead agency for this project for the requirements of the California Environmental Quality Act (CEQA).

Additionally, the Avenal Energy Project is subject to Prevention of Significant Deterioration requirements by EPA Region IX.

II. APPLICABLE RULES:

Rule 1080	Stack Monitoring (12/17/92)
Rule 1081	Source Sampling (12/16/93)
Rule 1100	Equipment Breakdown (12/17/92)
Rule 2010	Permits Required (12/17/92)
Rule 2201	New and Modified Stationary Source Review Rule (9/21/06)
Rule 2520	Federally Mandated Operating Permits (6/21/01)
Rule 2540	Acid Rain Program (11/13/97)
Rule 2550	Federally Mandated Preconstruction Review for Major Sources of Air Toxics (6/18/98)
Rule 4001	New Source Performance Standards (4/14/99) Subpart GG - Standards of Performance for Stationary Gas Turbines Subpart KKKK – Standards of Performance for Stationary Combustion Turbines
Rule 4002	National Emissions Standards for Hazardous Air Pollutants (5/18/00)

Rule 4101 Visible Emissions (2/17/05)
Rule 4102 Nuisance (12/17/92)
Rule 4201 Particulate Matter Concentration (12/17/92)
Rule 4202 Particulate Matter Emission Rate (12/17/92)
Rule 4301 Fuel Burning Equipment (12/17/92)
Rule 4305 Boilers, Steam Generators and Process Heaters – Phase 2 (8/21/03)
Rule 4306 Boilers, Steam Generators and Process Heaters – Phase 3 (3/17/05)
Rule 4351 Boilers, Steam Generators and Process Heaters – Phase 1 (8/21/03)
Rule 4701 Stationary Internal Combustion Engines – Phase 1 (8/21/03)
Rule 4702 Stationary Internal Combustion Engines – Phase 2 (1/18/07)
Rule 4703 Stationary Gas Turbines (8/17/06)
Rule 4801 Sulfur Compounds (12/17/92)
Rule 8011 General Requirements (8/19/04)
Rule 8021 Construction, Demolition, Excavation, Extraction and Other Earthmoving Activities (8/19/04)
Rule 8031 Bulk Materials (8/19/04)
Rule 8041 Carryout and Trackout (8/19/04)
Rule 8051 Open Areas (8/19/04)
Rule 8061 Paved and Unpaved Roads (8/19/04)
Rule 8071 Unpaved Vehicle/Equipment Traffic Areas (9/16/04)
Rule 8081 Agricultural Sources (9/16/04)
California Environmental Quality Act (CEQA)
California Code of Regulations (CCR), Section 2423 (Exhaust Emission Standards and Test Procedures, Off-Road Compression-Ignition Engines and Equipment)
California Health & Safety Code (CH&S), Sections 2423 (Exhaust Emission Standards and Test Procedures, Off-Road Compression-Ignition Engines and Equipment) 41700 (Health Risk Analysis), 42301.6 (School Notice), 44300 (Air Toxic "Hot Spots"), and 93115 (Airborne Toxic Control Measure (ATCM) for Stationary Compression-Ignition (CI) Engines)

III. PROJECT LOCATION:

The proposed equipment will be located within NE¼ Section 19, Township 21 South, Range 18 East – Mount Diablo Base Meridian on Assessor's Parcel Number 36-170-032 (See Attachment B). The closest population center is the residential district of Avenal approximately 6 miles to the southwest. The City of Huron is located approximately 8 miles to the north, and the City of Coalinga is located approximately 16 miles to the west.

The site is located northeast of the city of Avenal, in Kings County. The proposed location is not within 1,000' of a K-12 school.

IV. PROCESS DESCRIPTION:

Combined-Cycle Combustion Turbine Generators
Each natural gas-fired General Electric Frame 7 Model PG7241FA combined-cycle combustion turbine generator (CTG) will be equipped with Dry Low NO_X combustors, a selective catalytic reduction (SCR) system with ammonia injection, an oxidation catalyst, a duct burner, and a heat recovery steam generator (HRSG). Each CTG will drive an electrical generator to produce approximately 180 MW of electricity. The plant will be a "combined-cycle plant," since the gas turbine and a steam turbine both turn electrical generators and produce power.

Each CTG will turn an electrical generator, but will also produce power by directing exhaust heat through its HRSG, which supplies steam to the steam turbine nominally rated at 300 MW, which turns another electrical generator.

Since two HRSGs will feed a single steam turbine generator, this design is referred to as a "two-on-one" configuration.

The CTGs will utilize Dry Low NO_X (DLN) combustors, SCR with ammonia injection, and an oxidation catalyst to achieve the following emission rates:

NO_X: 2.0 ppmvd @ 15% O_2
VOC: 2.0 ppmvd @ 15% O_2
CO: 2.0 ppmvd @ 15% O_2
SO_X: 0.00282 lb/MMBtu (Hourly and Daily Limits; based on 1.0 gr S/100 dscf)
0.001 lb/MMBtu (Annual average; based on 0.36 gr S/100 dscf))
PM_{10}: 0.0107 lb/MMBtu

Continuous emissions monitoring systems (CEMs) will sample, analyze, and record NO_X, CO, and O_2 concentrations in the exhaust gas for each CTG.

Heat Recovery Steam Generators (HRSGs)
The HRSGs provide for the transfer of heat from the CTG exhaust gases to condensate and feedwater to produce stream. Each HRSG will be approximately 90 feet high and will have an exhaust stack approximately 145 feet tall by 19 feet in diameter. The size and shape of the HRSGs are specific to their intended purpose of high efficiency recycling of waste heat from the CTG.

The HRSGs will be multi-pressure, natural-circulation boilers equipped with transition ducts and duct burners. Pressure components of each HRSG include a low pressure (LP) economizer, LP evaporator, LP deaerator/drum, LP superheater, intermediate pressure (IP) economizer, IP evaporator, IP drum, IP superheaters, high pressure (HP) economizer, HP evaporator, HP drum, and HP superheaters and reheaters.

Superheated HP steam is produced in the HRSG and flows to the steam turbine throttle inlet. The exhausted cold reheat steam from the steam turbine is mixed with IP steam from the HRSG and reintroduced into the HRSG through the reheaters. The hot reheat steam flows back from the HRSG into the STG. The LP superheated steam from the HRSG is admitted to the LP condenser. The condensate is pumped from the condenser back to the HRSG by condensate pumps. The condensate is preheated by an HRSG feedwater heater. Boiler feedwater pumps send the feedwater through economizers and into the boiler drums of the HRSG, where steam is produced, thereby completing the steam cycle.

Each HRSG is equipped with a SCR system that uses aqueous ammonia in conjunction with a catalyst bed to reduce NO_X in the CTG exhaust gases. The catalyst bed is contained in a catalyst chamber located within each HRSG. Ammonia is injected upstream of the catalyst bed. The subsequent catalytic reaction converts NO_X to nitrogen and water, resulting in a reduced concentration of NO_X in the exhaust gases exiting the stack.

Duct Burners

Duct burners are installed in the HRSG transition duct between the HP superheater and reheat coils. Through the combustion of natural gas, the duct burners heat the CTG exhaust gases to generate additional steam at times when peak power is needed. The duct burners are also used as needed to control the temperature of steam produced by the HRSGs. The duct burners will have a maximum heat input rating of 562 MMBtu/hr on a higher heating value (HHV) basis per HRSG, and are expected to operate no more than 800 hours per year.

Steam Turbine Generator

The steam turbine system consists of a 300 MW nominally rated reheat steam turbine generator (STG), governor system, steam admission system, gland steam system, lubricating oil system, including oil coolers and filters and generator coolers. Steam from the HP superheater, reheater and IP superheater sections of the HRSG enters the corresponding sections of the STG as described previously. The steam expands through the turbine blading to drive the steam turbine and its generator. Upon exiting the turbine, the steam enters the deaerating condenser, where it is condensed to water.

Auxiliary Boiler

One 37.4 MMBtu/hr Cleaver Brooks Model CBL700-900-200#ST natural gas-fired boiler equipped with an Cleaver Brooks Model ProFire Ultra Low NO_X burner, capable of providing up to 25,000 pounds per hour (lb/hr) of saturated steam. The boiler will be used to provide steam as needed for auxiliary purposes.

Diesel-Fired Emergency IC Engine Powering a Fire Pump

Emergency firewater will be provided by three pumps (a jockey pump, a main fire pump, and a back-up fire pump); two powered by electric motors and the other powered by a diesel-fired internal combustion engine. If the jockey pump is unable to maintain a set operating pressure in the piping network, the electric motor-driven fire pump will start automatically. If the electric motor-driven fire pump is unable to maintain a set operating pressure, the diesel engine-driven fire pump will start automatically. The diesel-fired engine will be rated at 288 horsepower. The engine will be limited to no greater than 50 hours per year of non-emergency operation in accordance with the applicant's proposal.

Natural Gas-Fired Emergency IC Engine Powering an Electrical Generator
One 860 hp Caterpillar Model G3512LE natural gas-fired IC engine generator set will provide power to the essential service AC system in the event of grid failure or loss of outside power to the plant. This engine will be limited to no greater than 50 hours per year of non-emergency operation in accordance with the applicant's proposal.

V. EQUIPMENT LISTING:

C-3953-10-0: 180 MW NOMINALLY RATED COMBINED-CYCLE POWER GENERATING SYSTEM #1 CONSISTING OF A GENERAL ELECTRIC FRAME 7 MODEL PG7241FA NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR WITH DRY LOW NO_X COMBUSTOR, A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM, AN OXIDATION CATALYST, HEAT RECOVERY STEAM GENERATOR #1 (HRSG) WITH A 562 MMBTU/HR DUCT BURNER AND A 300 MW NOMINALLY RATED STEAM TURBINE SHARED WITH C-3953-11

C-3953-11-0: 180 MW NOMINALLY RATED COMBINED-CYCLE POWER GENERATING SYSTEM #2 CONSISTING OF A GENERAL ELECTRIC FRAME 7 MODEL PG7241FA NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR WITH DRY LOW NO_X COMBUSTOR, A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM, AN OXIDATION CATALYST, HEAT RECOVERY STEAM GENERATOR #2 (HRSG) WITH A 562 MMBTU/HR DUCT BURNER AND A 300 MW NOMINALLY RATED STEAM TURBINE SHARED WITH C-3953-10

C-3953-12-0: 37.4 MMBTU/HR CLEAVER BROOKS MODEL CBL-700-900-200#ST NATURAL GAS-FIRED BOILER WITH A CLEAVER BROOKS MODEL PROFIRE, OR DISTRICT APPROVED EQUIVALENT, ULTRA LOW NOX BURNER

C-3953-13-0: 288 BHP CLARKE MODEL JW6H-UF40 DIESEL-FIRED EMERGENCY IC ENGINE POWERING A FIRE PUMP

C-3953-14-0: 860 BHP CATERPILLAR MODEL 3456 NATURAL GAS-FIRED EMERGENCY IC ENGINE POWERING WITH NON-SELECTIVE CATALYTIC REDUCTION (NSCR) POWERING A 500 KW ELECTRICAL GENERATOR

VI. EMISSION CONTROL TECHNOLOGY EVALUATION:

i. C-3953-10-0 and C-3953-11-0 (Turbines)

Each CTG will be equipped with a Dry Low NO_X combustor and will exhaust into a Selective Catalytic Reduction [SCR] system with ammonia injection, and a CO catalyst. The use of Dry Low NO_X combustors and a SCR system with ammonia injection can achieve a NO_X emission rate of 2.0 ppmvd @ 15% O_2. CO emissions of 2.0 ppmvd @

15% O_2 have been demonstrated with the use of an oxidation catalyst [1]. And the use of DLN combustors and good combustion practices can achieve VOC emissions of 2.0 ppmvd @ 15% O_2.

Emissions from natural gas-fired turbines include NO_X, CO, VOC, PM_{10}, and SO_X.

NO_X is the major pollutant of concern when combusting natural gas. Virtually all gas turbine NO_X emissions originate as NO. This NO is further oxidized in the exhaust system or later in the atmosphere to form the more stable NO_2 molecule. There are two mechanisms by which NO_X is formed in turbine combustors: 1) the oxidation of atmospheric nitrogen found in the combustion air (thermal NO_X and prompt NO_X), and 2) the conversion of nitrogen chemically bound in the fuel (fuel NO_X).

Thermal NO_X is formed by a series of chemical reactions in which oxygen and nitrogen present in the combustion air dissociate and subsequently react to form oxides of nitrogen. Prompt NO_X, a form of thermal NO_X, is formed in the proximity of the flame front as intermediate combustion products such as HCN, H, and NH are oxidized to form NO_X. Prompt NO_X is formed in both fuel-rich flame zones and dry low NO_X (DLN) combustion zones. The contribution of prompt NO_X to overall NO_X emissions is relatively small in conventional near-stoichiometric combustors, but this contribution is an increasingly significant percentage of overall thermal NO_X emissions in DLN combustors. For this reason prompt NO_X becomes an important consideration for DLN combustor designs, and establishes a minimum NO_X level attainable in lean mixtures.

Fuel NO_X is formed when fuels containing nitrogen are burned. Molecular nitrogen, present as N_2 in some natural gas, does not contribute significantly to fuel NO_X formation. With excess air, the degree of fuel NO_X formation is primarily a function of the nitrogen content in the fuel. When compared to thermal NO_X, fuel NO_X is not currently a major contributor to overall NO_X emissions from stationary gas turbines firing natural gas.

The level of NO_X formation in a gas turbine, and hence the NO_X emissions, is unique (by design factors) to each gas turbine model and operating mode. The primary factors that determine the amount of NO_X generated are the combustor design, the types of fuel being burned, ambient conditions, operating cycles, and the power output of the turbine.

The design of the combustor is the most important factor influencing the formation of NO_X. Design parameters controlling air/fuel ratio and the introduction of cooling air into the combustor strongly influence thermal NO_X formation. Thermal NO_X formation is primarily a function of flame temperature and residence time. The extent of fuel/air mixing prior to combustion also affects NO_X formation. Simultaneous mixing and combustion results in localized fuel-rich zones that yield high flame temperatures in which substantial thermal NO_X production takes place. Injecting water or steam into a conventional combustor provides a heat sink that effectively reduces peak flame temperature, thereby reducing thermal NO_X formation. Premixing air and fuel at a lean ratio approaching the lean

[1] Based on information supplied by the CTG manufacturer and information contained in the California Air Resources Board's September 1999 Guidance for Power Plant Siting and Best Available Control Technology document.

flammability limit (approximately 50% excess air) significantly reduces peak flame temperature, resulting in minimum NO_X formation during combustion. This is known as dry low NO_X (DLN) combustion.

Selective Catalytic Reduction systems selectively reduce NO_X emissions by injecting ammonia (NH_3) into the exhaust gas stream upstream of a catalyst. Nitrogen oxides, NH_3, and O_2 react on the surface of the catalyst to form molecular nitrogen (N_2) and H_2O. SCR is capable of over 90 percent NO_X reduction. Titanium oxide is the SCR catalyst material most commonly used, though vanadium pentoxide, noble metals, or zeolites are also used. The ideal operating temperature for a conventional SCR catalyst is 600 to 750 °F. Exhaust gas temperatures greater than the upper limit (750 °F) will cause NO_X and NH_3 to pass through the catalyst unreacted. Ammonia slip will be limited to 10 ppmvd @ 15% O_2.

Carbon monoxide is formed during the combustion process due to incomplete oxidation of the carbon contained in the fuel. Carbon monoxide formation can be limited by ensuring complete and efficient combustion of the fuel. High combustion temperatures, adequate excess air and good air/fuel mixing during combustion minimize CO emissions. Therefore, lowering combustion temperatures and staging combustion to limit NO_X formation can result in increased CO emissions.

Post-combustion CO controls, such as oxidizing catalysts can also be used to reduce CO emissions. An oxidation catalyst utilizes a precious metal catalyst bed to convert carbon monoxide (CO) to carbon dioxide (CO_2).

Inlet air temperature and density directly affects turbine performance. The hotter and drier the inlet air temperature, the lower the efficiency and capacity of the turbine. Conversely, colder air improves the efficiency and reduces emissions by reducing the amount of fuel required to achieve the required turbine output. The inlet air cooler will allow the turbine to operate in a more efficient manner than it would without it. The increased efficiency will reduce the amount of fuel necessary to achieve the required power output. The reduction in fuel consumption will result in lower combustion contaminant emissions.

The inlet air filter will remove particulate matter from the combustion air stream, reducing the amount of particulate matter emitted.

The lube oil coalescer will result in the merging together of oil mist to form larger droplets. The larger droplets will return to the oil stream instead of being emitted.

ii. C-3953-12-0 (Boiler)

Emissions from natural gas-fired boilers include NO_X, CO, VOC, PM_{10}, and SO_X.

NO_X is the major pollutant of concern when burning natural gas. NO_X formation is either due to thermal fixation of atmospheric nitrogen in the combustion air (thermal NO_X) or due to conversion of chemically bound nitrogen in the fuel (fuel NO_X). Due to the low fuel nitrogen content of natural gas, nearly all NO_X emissions are thermal NO_X. Formation of thermal NO_X is affected by four furnace zone factors: (1) nitrogen concentration, (2) oxygen concentration, (3) peak temperature, and (4) time of exposure at peak temperature.

The Cleaver Brooks boiler will control the formation of thermal NO_X with an Cleaver Brooks ultra low NO_X burner. Cleaver Brooks burners reduce NO_X by pre-mixing gaseous fuel and combustion air in a region near the burner exit, at a stoichiometry that minimizes Prompt NO_X. This also eliminates the traditional NO_X versus CO tradeoff.

iii. C-3953-13-0 (Diesel IC engine powering fire water pump)

The diesel-fired emergency IC engine (fire pump) will be equipped with a turbocharger, an intercooler/aftercooler, and will be fired on very low (0.0015%) sulfur diesel.

The emission control devices/technologies and their effect on diesel engine emissions are detailed below.[2]

The turbocharger reduces the NO_X emission rate from the engine by approximately 10% by increasing the efficiency and promoting more complete burning of the fuel.

The intercooler/aftercooler functions in conjunction with the turbocharger to reduce the inlet air temperature. By reducing the inlet air temperature, the peak combustion temperature is lowered, which reduces the formation of thermal NO_X. NO_X emissions are reduced by approximately 15% with this control technology.

The use of low sulfur (0.0015% by weight sulfur maximum) diesel fuel reduces SO_X emissions by approximately 99% from standard diesel fuel.

iv. C-3953-14-0 (Natural gas IC engine powering electrical generator)

The natural gas-fired emergency IC engine (generator) will be equipped with an intercooler/aftercooler, lean burn technology, and will be fired on PUC-Regulated natural gas.

The emission control devices/technologies and their effect on diesel engine emissions are detailed below.[3]

The intercooler/aftercooler functions in conjunction with the turbocharger to reduce the inlet air temperature. By reducing the inlet air temperature, the peak combustion temperature is lowered, which reduces the formation of thermal NO_X. NO_X emissions are reduced by approximately 15% with this control technology.

Lean burn technology increases the volume of air in the combustion process and therefore increases the heat capacity of the mixture. This technology also incorporates improved

[2] From "Non-catalytic NO_x Control of Stationary Diesel Engines", by Don Koeberlein, CARB.
[3] From "Non-catalytic NO_x Control of Stationary Diesel Engines", by Don Koeberlein, CARB.

swirl patterns to promote thorough air/fuel mixing. This in turn lowers the combustion temperature and reduces NO_X formation.

VII. GENERAL CALCULATIONS:

i. C-3953-10-0 and C-3953-11-0 (Turbines)

- Heating value of natural gas is 1,013 Btu/scf (per applicant).
- Maximum daily emissions for each CTG for VOC, PM_{10} and SO_X during the commissioning period are estimated assuming twenty-four (24) hours operating while firing at full load.
- The commissioning period will not exceed 408 hours per CTG and the emissions emitted during the commissioning period will accrue towards the maximum annual emissions limit.
- Maximum daily emissions for each CTG for NO_X, CO, and VOC are estimated assuming six (6) hours operating in startup and shutdown mode and eighteen (18) hours operating while firing at full load with operation of the duct burner.
- Maximum daily emissions for each CTG for PM_{10}, SO_X, and NH_3 are estimated assuming twenty-four (24) hours operating while firing at full load with the operation of the duct burner.
- Maximum annual emissions for each CTG for NO_X and VOC are estimated assuming the CTG is operated according to a weekend and weekday hot start scenario. The weekend and weekday hot start scenario results in CTG operation of 547.5 (1.5 hr/hot start x 365 hot start/yr) hours operating in startup and shutdown mode, 800 hours operating while firing at full load with the duct burner, and 6,683 hours operating while firing at full load without the duct burner.
- Maximum annual emissions for each CTG for CO are estimated assuming the CTG is operated according to a weekend shutdown and weekday hot start scenario. The weekend shutdown and weekday hot start scenario results in CTG operation of 624 ((1.5 hr/hot start x 208 hot start/yr) + (6.0 hr/cold start x 52 cold starts/year)) hours operating in startup and shutdown mode, 800 hours operating while firing at full load with the duct burner, and 3,800 hours operating while firing at full load without the duct burner.
- Maximum annual emissions for each CTG for PM_{10}, SO_X, and NH_3 are estimated assuming the CTG is operated according to a baseload scenario. The baseload scenario results in CTG operation of 800 hours operating while firing at full load with the duct burner and 7,960 hours operating while firing at full load without the duct burner.

ii. C-3953-12-0 (Boiler)

- External O_2 stack gas concentration is 3%.
- Natural gas F factor is 8,710 dscf/MMBtu (Ref. 40 CFR Part 60, Appendix A, Method 19).
- Heating value of natural gas is 1,013 Btu/scf (per applicant).
- The applicant is proposing a maximum natural gas usage rate of 37.4 MMBtu/hr.
- Maximum SO_X emission factor determined by performing a mass balance assuming a natural gas sulfur content of 1 gr S/100 scf. Calculation shown below.

$(1\ \cancel{gr\text{-}S}/100\ \cancel{dscf} \times 1\ \cancel{lb\text{-}S}/7000\ \cancel{gr} \times 64\ lb\ SO_X/32\ \cancel{lb\text{-}S} \times 1\ \cancel{scf}/1013\ \cancel{Btu} \times 10^6\ \cancel{Btu}/MMBtu)$
$= 0.00282\ lb/MMBtu$

- Maximum daily and annual emissions for all pollutants are estimated assuming twelve (12) hours per day and 1,248 hours per year operating at full load.[4]
- Operating schedule of 12 hr/day and 1,248 hrs/year.

iii. C-3953-13-0 (Diesel IC engine powering fire water pump)

- Diesel F factor (adjusted to 60 °F) is 9,051 dscf/MMBtu.
- Density of diesel is 7.1 lb/gal.
- Higher heating value of diesel is 137,000 Btu/scf.
- BHP to Btu/hr conversion is 2,542.5 Btu/hp·hr.
- Thermal efficiency of the engine: commonly ≈ 35%.
- Emissions are based on 24 hours per day (maximum emergency use) and 50 hours per year of operation (maximum non-emergency use).

iV. C-3953–14-0 (Natural gas IC engine powering electrical generator)

- EPA F-factor (adjusted to 60 °F) is 8,578 dscf/MMBtu (40 CFR 60 Appendix B)
- Fuel heating value 1,013 Btu/dscf (per applicant)
- Maximum daily SO_X emission factor determined by performing a mass balance assuming a natural gas sulfur content of 1 gr S/100 scf. Calculation shown below.

$(1\ \cancel{gr\text{-}S}/100\ \cancel{dscf} \times 1\ \cancel{lb\text{-}S}/7000\ \cancel{gr} \times 64\ lb\ SO_X/32\ \cancel{lb\text{-}S} \times 1\ \cancel{scf}/1013\ \cancel{Btu} \times 10^6\ \cancel{Btu}/MMBtu)$
$= 0.00282\ lb/MMBtu$

- BHP to Btu/hr conversion is 2,542.5 Btu/hp·hr.
- Thermal efficiency of the engine: commonly ≈ 35%.
- Emissions are based on 24 hours per day (maximum emergency use) and 50 hours per year of operation (maximum non-emergency use).

[4] Applicant has indicated that the unit will be used a maximum of 12 hours on a startup day.

B. Emission Factors

i. C-3953-10-0 and C-3953-11-0 (Turbines)

The maximum air contaminant mass emission rates (lb/hr) during the commissioning period estimated by the facility (see Attachment C) for the proposed CTGs are summarized below:

Commissioning Period Emissions					
	NO_X	CO	VOC	PM_{10}	SO_X
Mass Emission Rate (per turbine, lb/hr)	160	1,000	16	N/A[5]	N/A[5]

The maximum air contaminant mass emission rates (lb/hr) with and without duct burner firing, concentrations (ppmvd @ 15% O_2), and startup and shutdown emissions rates (lb/hr) provided by the applicant (see Attachment D for applicant proposed emissions) for the proposed CTGs are summarized below.

The emission rates from the turbines and duct burners are calculated below:

Maximum Emission Rate Without Duct Burner Firing:

The worst-case NO_X, PM_{10}, CO, VOC, and NH_3 mass emission rates are when each turbine operates at 100% load and an ambient air inlet temperature of 32 °F. The worst-case SO_X mass emission rate will be determined assuming a natural gas sulfur content of 1 gr S/100 scf. The following equation will be used to calculate the emission rate of the CTG without the duct burner firing:

Emission Rate (lb/hr) = CTG Max Heat Input (MMBtu/hr) x Emission Factor (lb/MMBtu)

NO_X Emission Rate (lb/hr) = (1,856.3 MMBtu/hr) x (0.0073 lb-NO_X/MMBtu)
= **13.55 lb-NO_X/hr**

CO Emission Rate (lb/hr) = (1,856.3 MMBtu/hr) x (0.0045 lb-CO/MMBtu)
= **8.35 lb-CO/hr**

VOC Emission Rate (lb/hr) = (1,856.3 MMBtu/hr) x (0.0018 lb-VOC/MMBtu)
= **3.34 lb-VOC/hr**

PM_{10} Emission Rate (lb/hr) = (1,856.3 MMBtu/hr) x (0.0048 lb-PM_{10}/MMBtu)
= **8.91 lb-PM_{10}/hr**

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[5] PM_{10} and SO_X emissions during commissioning period are equal to the maximum hourly emissions during baseload facility operation.

SO_X Emission Rate (lb/hr) = (1,856.3 MMBtu/hr) x (0.00282 lb-SO_X/MMBtu)
= 5.23 lb-SO_X/hr

NH3 Emission Rate (lb/hr) = ppm x MW x (2.64×10^{-9}) x ff x HV x FL x [20.9 / (20.9 – O_2%)]

Where:
ppm is the emission concentration in ppmvd @ 15% O_2 (10 ppmv)
MW is the molecular weight of the pollutant: (MW_{NH3} = 17 lb/lb-mol)
2.64 x 10^{-9} is one over the molar specific volume (lb-mol/MMscf, at 60 °F)
ff is the F-factor for natural gas: (8,578 scf/MMBtu, at 60 °F)
HV is the heating value of natural gas: (1,013 Btu/scf)
FL is the amount of natural gas each turbine can burn in any given hour: (CTG w/o duct burner 1.832 MMscf/hour, as calculated below)
(1,856.3 MMBtu/hr) ÷ (1,013 MMBtu/MMscf) = 1.832 MMscf/hr
O_2 is the stack oxygen content to which the emission concentrations are corrected: (15%)

NH_3 Emission Rate (lb/hr) = 10 x 17 x (2.64×10^{-9}) (lb-mol/MMscf) x 8,578 (scf/MMBtu) x 1,013 (Btu/scf) x 1.832 (MMscf/hr) x [20.9 / (20.9 – 15.0)]
= 25.31 lb-NH3/hr

Maximum Emission Rates and Concentrations Without Duct Burner Firing (@ 100% Load & 32 °F)						
	NO_X	CO	VOC	PM_{10}	SO_X	NH_3
Mass Emission Rates (per turbine, lb/hr)	13.55	8.35	3.34	8.91	5.23	25.31
ppmvd @ 15% O_2 limits	2.0	2.0	1.4	--	--	10.0
lb/MMBtu*	0.0073	0.0045	0.0018	0.0048	0.00282	--

* Emission factors were taken from Table 6.2-1.1 in the ATC application submittal.

<u>Maximum Emission Rate With Duct Burner Firing:</u>

The worst-case NO_X, SO_X, PM_{10}, CO, VOC, and NH_3 mass emission rates are when each turbine operates at 100% load and an ambient air inlet temperature of 101 °F. The worst-case SO_X mass emission rate will be determined assuming a natural gas sulfur content of 1 gr S/100 scf. The following equation will be used to calculate the emission rate of the CTG with the duct burner firing:

Emission Rate (lb/hr) = [CTG Max Heat Input + Duct Burner Max Heat Input] (MMBtu/hr) x Emission Factor (lb/MMBtu)

NO_X Emission Rate (lb/hr) = (2,356.5 MMBtu/hr) x (0.0073 lb-NO_X/MMBtu)
= 17.20 lb-NO_X/hr

CO Emission Rate (lb/hr) = (2,356.5 MMBtu/hr) x (0.0045 lb-CO/MMBtu)
= **10.60 lb-CO/hr**

VOC Emission Rate (lb/hr) = (2,356.5 MMBtu/hr) x (0.0025 lb-VOC/MMBtu)
= **5.89 lb-VOC/hr**

PM_{10} Emission Rate (lb/hr) = (2,356.5 MMBtu/hr) x (0.0050 lb-PM_{10}/MMBtu)
= **11.78 lb-PM_{10}/hr**

SO_X Emission Rate (lb/hr) = (2,356.5 MMBtu/hr) x (0.00282 lb-SO_X/MMBtu)
= **6.65 lb-SO_X/hr**

NH3 Emission Rate (lb/hr) = ppm x MW x (2.64×10^{-9}) x ff x HV x FL x [20.9 / (20.9 – O_2%)]

Where:
ppm is the emission concentration in ppmvd @ 15% O_2 (10 ppmv)
MW is the molecular weight of the pollutant: (MW_{NH3} = 17 lb/lb-mol)
2.64 x 10^{-9} is one over the molar specific volume (lb-mol/MMscf, at 60 °F)
ff is the F-factor for natural gas: (8,578 scf/MMBtu, at 60 °F)
HV is the heating value of natural gas: (1,013 Btu/scf)
FL is the amount of natural gas each turbine can burn in any given hour: (CTG w duct burner 2.326 MMscf/hour, as calculated below)
(2,356.5 MMBtu/hr) ÷ (1,013 MMBtu/MMscf) = 2.326 MMscf/hr
O_2 is the stack oxygen content to which the emission concentrations are corrected: (15%)

NH_3 Emission Rate (lb/hr) = 10 x 17 x (2.64×10^{-9}) (lb-mol/MMscf) x 8,578 (scf/MMBtu) x 1,013 (Btu/scf) x 2.326 (MMscf/hr) x [20.9 / (20.9 – 15.0)]
= **32.13 lb-NH3/hr**

Maximum Emission Rates and Concentrations With Duct Burner Firing (@ 100% Load & 101 °F)						
	NO_X	CO	VOC	PM_{10}	SO_X	NH_3
Mass Emission Rates (per turbine, lb/hr)	17.20	10.60	5.89	11.78	6.65	32.13
ppmvd @ 15% O_2 limits	2.0	2.0	2.0	--	--	10.0
lb/MMBtu*	0.0074	0.0045	0.0025	0.0050	0.00282	--

* Emission factors were taken from Table 6.2-1.1 in the ATC application submittal.

Startup and Shutdown Emissions					
	NO_X	CO	VOC	PM_{10}	SO_X
Maximum Mass Emission Rate (per turbine, lb/hr)	160	1,000	16	N/A[6]	N/A[6]
Average Mass Emission Rate (per turbine, lb/hr)	80	900	16	N/A[6]	N/A[6]

ii. C-3953-12-0 (Boiler)

For the new boiler, the emissions factors for NO_X, CO, VOC, and PM_{10} are provided by the applicant. The SO_X emission factor is calculated as shown below.

Boiler Emission Factors*		
Pollutant	ppmv @ 3%O_2	lb/MMBtu
NO_X	9.0	0.011
CO	50.0	0.037
VOC	10.0	0.0043
PM_{10}	--	0.005
SO_X**	--	0.00282

*Note: lb/MMBtu equivalent of ppmv values @ 3% O_2 as provided by the Applicant
** SO_X emission factor based on the maximum proposed sulfur content of 1 gr/100 dscf.

(1 ~~gr-S~~/100 ~~dscf~~ x 1 ~~lb-S~~/7000 ~~gr~~ x 64 lb SO_X/32 ~~lb-S~~ x 1 ~~scf~~/1013 ~~Btu~~ x 10^6 ~~Btu~~/MMBtu)
= 0.00282 lb/MMBtu

iii. C-3953-13-0 (Diesel IC engine powering fire water pump)

For the new emergency diesel-fired IC engine powering a fire water pump, the emissions factors for NO_X, CO, VOC, and PM_{10} are provided by the applicant and are guaranteed by the engine manufacturer. The SO_X emission factor is calculated using the sulfur content in the diesel fuel (0.0015% sulfur).

[6] PM_{10} and SO_X emissions during startups and shutdowns are lower than maximum hourly emissions during baseload facility operation.

Diesel-fired IC Engine Emission Factors		
	g/hp·hr	Source
NO_X	3.4	Engine Manufacturer
CO	0.447	Engine Manufacturer
VOC	0.38	Engine Manufacturer
PM_{10}	0.059	Engine Manufacturer
*SO_X	0.005	Mass Balance Equation Below

$$^{*}0.0015\% \times \frac{7.1\, lb \cdot fuel}{gallon} \times \frac{2\, lb \cdot SO_2}{1\, lb \cdot S} \times \frac{1\, gal}{137{,}000\, Btu} \times \frac{1\, hp\ input}{0.35\, hp\ out} \times \frac{2{,}542.5\, Btu}{hp \cdot hr} \times \frac{453.6\, g}{lb} = 0.005\, \frac{g\ SOx}{hp \cdot hr}$$

iv. C-3953-14-0 (Natural gas IC engine powering electrical generator)

For the new emergency natural gas-fired IC engine powering an electrical generator, the emissions factors for NO_X, CO, VOC, and PM_{10} are provided by the applicant and are guaranteed by the engine manufacturer. The SO_X emission factor is calculated using the fuel sulfur content from District Policy APR 1720.

Natural Gas-fired IC Engine Emission Factors		
	g/hp·hr	Source
NO_X	1.0	Engine Manufacturer
CO	0.6	Engine Manufacturer
VOC	0.33	Engine Manufacturer
PM_{10}	0.034	Engine Manufacturer
**SO_X	0.0094	Mass Balance Equation Below

**SO_X is calculated as follows:

$$0.00285\ \frac{lb - SO_x}{MMBtu} \times \frac{1\, MMBtu}{1{,}000{,}000\, Btu} \times \frac{2{,}542.5\, Btu}{bhp - hr} \times \frac{1\, bhp\ input}{0.35\, bhp\ out} \times \frac{453.6\, g}{lb} = 0.0094\ \frac{g - SO_x}{bhp - hr}$$

C. <u>Calculations</u>

1. Pre-Project Potential to Emit (PE1)

Section 3.26 of Rule 2201 defines the potential to emit (PE) as the maximum capacity of an emissions unit to emit a pollutant under its physical and operational design. Since this is a brand new facility, the pre-project potential to emit (PE1) for all the emissions units associated with this project is equal to zero.

2. Post Project Potential to Emit (PE2):

i. C-3953-10-0 and C-3953-11-0 (Turbines)

a. Maximum Hourly PE

The maximum hourly potential to emit for NO_X, CO, and VOC from each CTG will occur when the unit is operating under start-up mode. The maximum hourly PE for both turbines operating together is when both are starting up and firing their duct burners.

The combined startup NOx emissions from the two turbines will be limited to 240 lbs/hr [maximum startup emission rate (160 lbs/hr) + average startup emission rate (80 lbs/hr)]. Similarly, the combined startup CO emissions from the two turbines will be limited to 1,902 lbs/hr, [maximum startup emission rate (1,000 lbs/hr) + average startup emission rate (902 lbs/hr)].

The maximum hourly emissions are summarized in the table below:

Maximum Hourly Potential to Emit					
	Maximum Startup/Shutdown Emissions (lb/hr)	Turbine w/ Duct Burner Emissions Rate	Turbine #1 Emissions (lb/hr)	Turbine #2 Emissions (lb/hr)	Maximum Hourly Emissions for Both Turbines
NO_X	160	17.20	13.55	13.55	240.00
CO	1,000	10.60	8.35	8.35	1,902.00
VOC	16	5.89	3.34	3.34	32.00
PM_{10}	N/A[7]	11.78	8.91	8.91	23.56
SO_X	N/A[7]	6.65	5.23	5.23	13.30
NH_3	N/A	32.13	25.31	25.31	64.26

b. Maximum Daily PE

Maximum daily emissions for NO_X, CO, and VOC occurs when each CTG undergoes six (6) hours operating in startup or shutdown mode, and eighteen (18) hours operating with duct burner firing at full load. The startup and shutdown emissions for PM_{10}, SO_X, and NH3 are will be lower or equivalent to the emissions rate when the unit is fired at 100% load; therefore the maximum daily emissions for PM_{10}, SO_X, and NH3 occurs when each CTG is operated for twenty four (24) hours with duct burner firing at full load. The results are summarized in the table below:

[7] PM_{10} and SO_X emissions during startups and shutdowns are lower than maximum hourly emissions.

Maximum Daily Potential to Emit (w/ Startup and Shutdown)				
	Average Startup/Shutdown Emissions Rate	Emissions Rate @ 100% Load with duct burner (101° F)	Emissions Rate @ 100% Load without duct burner (32° F)	DEL (per CTG)
NO_X	80 lb/hr (avg)	17.20 lb/hr	13.03 lb/hr	789.6 lb/day
CO	900 lb/hr (avg)	10.60 lb/hr	8.35 lb/hr	5,590.8 lb/day
VOC	16 lb/hr (avg)	5.89 lb/hr	3.34 lb/hr	202.0 lb/day
PM_{10}	N/A(8)	11.78 lb/hr	8.91 lb/hr	282.7 lb/day
SO_X	N/A(8)	6.65 lb/hr	5.23 lb/hr	159.6 lb/day
NH_3	N/A	32.13 lb/hr	25.31 lb/hr	771.1 lb/day

c. Maximum Annual PE

The facility has indicated that the turbines will be operated in one of three different scenarios: weekend and weekday hot start scenario, weekend shutdown and weekday hot start scenario, and baseload scenario. The SO_X emission factors used to calculate the annual potential emissions will be based on the applicant proposed average natural gas sulfur limit 0.36 gr/100 dscf.

SO_X EF = (0.36 $\cancel{\text{gr-S}}$/100 $\cancel{\text{dscf}}$) x (1 $\cancel{\text{lb-S}}$/7000 $\cancel{\text{gr}}$) x (64 lb SO_X/32 $\cancel{\text{lb-S}}$) x (1 $\cancel{\text{scf}}$/1013 $\cancel{\text{Btu}}$) x (10^6 $\cancel{\text{Btu}}$/MMBtu)
= 0.001 lb-SO_X/MMBtu

<u>CTG w/o Duct Burner Firing:</u>
SO_X Emission Rate (lb/hr) = (1,856.3 MMBtu/hr) x (0.001 lb-SO_X/MMBtu)
= **1.86 lb-SO_X/hr**

<u>CTG w/ Duct Burner Firing:</u>
SO_X Emission Rate (lb/hr) = (2,356.5 MMBtu/hr) x (0.001 lb-SO_X/MMBtu)
= **2.36 lb-SO_X/hr**

Potential annual emissions for each pollutant will be calculated for each of the three scenarios in the tables below:

Scenario 1) Weekend and Weekday Hot Start:

547.5 (1.5 hr/hot start x 365 hot start/yr) hours operating in startup and shutdown mode, 800 hours operating while firing at full load with the duct burner, and 6,683 hours operating while firing at full load without the duct burner. Since startup and shutdown emission rates for PM_{10}, SO_X, and NH3 are less than the emission rate when the CTG is fired at 100% load w/o the duct burner, the startup and shutdown emission rates will be assumed to be equivalent to the CTG fired at 100% load w/o the duct burner. Since the CTGs will be fired throughout the year, the emission factors for the unit when fired at the average ambient temperature (63° F) will be used to calculate the potential annual emissions.

Annual Potential to Emit Scenario 1) Weekend and Weekday Hot Start*				
	Average Startup/Shutdown Emissions Rate	Emissions Rate @ 100% Load with duct burner (63° F)	Emissions Rate @ 100% Load without duct burner (63° F)	Annual PE (per CTG))
NO_X	80 lb/hr (avg)	16.34 lb/hr	13.03 lb/hr	**143,951 lb/year**
CO	900 lb/hr (avg)	10.60 lb/hr	8.35 lb/hr	557,033 lb/year
VOC	16 lb/hr (avg)	5.68 lb/hr	3.17 lb/hr	**34,489 lb/year**
PM_{10}	N/A[8]	11.27 lb/hr	9.00 lb/hr	74,091 lb/year
SO_X	N/A[8]	2.36 lb/hr	1.86 lb/hr	15,337 lb/year
NH_3	N/A	32.13 lb/hr	25.31 lb/hr	208,708 lb/year

* Emission factors were taken from Table 6.2-1.1 in the ATC application submittal.

Scenario 2) Weekend Shutdown and Weekday Hot Start:

624 ((1.5 hr/hot start x 208 hot start/yr) + (6.0 hr/cold start x 52 cold starts/year)) hours operating in startup and shutdown mode, 800 hours operating while firing at full load with the duct burner, and 3,800 hours operating while firing at full load without the duct burner. Since startup and shutdown emission rates for PM_{10}, SO_X, and NH3 are less than the emission rate when the CTG is fired at 100% load w/o the duct burner, the startup and shutdown emission rates will be assumed to be equivalent to the CTG fired at 100% load w/o the duct burner. Since the CTGs will be fired throughout the year, the emission factors for the unit when fired at the average ambient temperature (63° F) will be used to calculate the potential annual emissions.

Annual Potential to Emit Scenario 2) Weekend Shutdown and Weekday Hot Start*				
	Average Startup/Shutdown Emissions Rate	Emissions Rate @ 100% Load with duct burner (63° F)	Emissions Rate @ 100% Load without duct burner (63° F)	Annual PE (per CTG)
NO_X	80 lb/hr (avg)	16.34 lb/hr	13.03 lb/hr	112,506 lb/year
CO	900 lb/hr (avg)	10.60 lb/hr	8.35 lb/hr	**601,810 lb/year**
VOC	16 lb/hr (avg)	5.68 lb/hr	3.17 lb/hr	26,574 lb/year
PM_{10}	N/A(8)	11.27 lb/hr	9.00 lb/hr	48,832 lb/year
SO_X	N/A(8)	2.36 lb/hr	1.86 lb/hr	10,117 lb/year
NH_3	N/A	32.13 lb/hr	25.31 lb/hr	137,675 lb/year

* Emission factors were taken from Table 6.2-1.1 in the ATC application submittal.

Scenario 3) Baseload:

800 hours operating while firing at full load with the duct burner, and 7,960 hours operating while firing at full load without the duct burner. Since the CTGs will be fired throughout the year, the emission factors for the unit when fired at the average ambient temperature (63° F) will be used to calculate the potential annual emissions.

Annual Potential to Emit Baseload Scenario*				
	Average Startup/Shutdown Emissions Rate	Emissions Rate @ 100% Load with duct burner (63° F)	Emissions Rate @ 100% Load without duct burner (63° F)	Annual PE (per CTG)
NO_X	80 lb/hr (avg)	16.34 lb/hr	13.03 lb/hr	116,791 lb/year
CO	900 lb/hr (avg)	10.60 lb/hr	8.35 lb/hr	74,946 lb/year
VOC	16 lb/hr (avg)	5.68 lb/hr	3.17 lb/hr	29,777 lb/year
PM_{10}	N/A(8)	11.27 lb/hr	9.00 lb/hr	**80,656 lb/year**
SO_X	N/A(8)	2.36 lb/hr	1.86 lb/hr	**16,694 lb/year**
NH_3	N/A	32.13 lb/hr	25.31 lb/hr	**219,972 lb/year**

* Emission factors were taken from Table 6.2-1.1 in the ATC application submittal.

Maximum Annual Potential to Emit:

The highest annual potential emissions, for each pollutant, from the three different scenarios will be taken to determine the maximum annual potential to emit for the CTG. The results are summarized in the table below:

Maximum Annual Potential to Emit		
	Annual PE (per CTG)	Scenario
NO_X	143,951 lb/year	Scenario 1
CO	601,810 lb/year	Scenario 2
VOC	34,489 lb/year	Scenario 2
PM_{10}	80,656 lb/year	Scenario 3
SO_X	16,694 lb/year	Scenario 3
NH_3	219,972 lb/year	Scenario 3

d. Maximum Quarterly PE

Maximum quarterly emissions for each unit will be determined by dividing the maximum annual emissions into 4 quarters:

Maximum Quarterly Potential to Emit						
	NO_X	CO	VOC	PM_{10}	SO_X	NH_3
1st Quarter	35,987.75	150,452.5	8,622.25	20,164	4,173.5	54,993
2nd Quarter	35,987.75	150,452.5	8,622.25	20,164	4,173.5	54,993
3rd Quarter	35,987.75	150,452.5	8,622.25	20,164	4,173.5	54,993
4th Quarter	35,987.75	150,452.5	8,622.25	20,164	4,173.5	54,993

ii. C-3953-12-0 (Boiler)

The potential to emit for the boiler is calculated as follows, and summarized in the table below.

PE_{NOx} = (0.011 lb/MMBtu) ∗ (37.4 MMBtu/hr)
= **0.41 lb NO_X/hr**

= (0.011 lb/MMBtu) ∗ (37.4 MMBtu/hr) ∗ (12 hr/day)
= **4.9 lb NO_X/day**

= (0.011 lb/MMBtu) ∗ (37.4 MMBtu/hr) ∗ (1,248 hr/year)
= **513 lb NO_X/year**

= (513 lb NO_X/year) ÷ (4 qtr/year)
= **128 lb NO_X/qtr**

PE_{CO} = (0.037 lb/MMBtu) * (37.4 MMBtu/hr)
= **1.38 lb CO/hr**

= (0.037 lb/MMBtu) * (37.4 MMBtu/hr) * (12 hr/day)
= **16.6 lb CO/day**

= (0.037 lb/MMBtu) * (37.4 MMBtu/hr) * (1,248 hr/year)
= **1,727 lb CO/year**

= (1,727 lb CO/year) * (4 qtr/year)
= **432 lb CO/qtr**

PE_{VOC} = (0.0043 lb/MMBtu) * (37.4 MMBtu/hr)
= **0.16 lb VOC/hr**

= (0.0043 lb/MMBtu) * (37.4 MMBtu/hr) * (12 hr/day)
= **1.9 lb VOC/day**

= (0.0043 lb/MMBtu) * (37.4 MMBtu/hr) * (1,248 hr/year)
= **201 lb VOC/year**

= (201 lb/year) * (4 qtr/year)
= **50 lb VOC/qtr**

PE_{PM10} = (0.005 lb/MMBtu) * (37.4 MMBtu/hr)
= **0.19 lb PM_{10}/hr**

= (0.005 lb/MMBtu) * (37.4 MMBtu/hr) * (12 hr/day)
= **2.2 lb PM_{10}/day**

= (0.005 lb/MMBtu) * (37.4 MMBtu/hr) * (1,248 hr/year)
= **233 lb PM_{10}/year**

= (233 lb/year) * (4 qtr/year)
= **58 lb PM_{10}/qtr**

PE_{SOx} = (0.00282 lb/MMBtu) * (37.4 MMBtu/hr)
= **0.11 lb SO_X/hr**

= (0.00282 lb/MMBtu) * (37.4 MMBtu/hr) * (12 hr/day)
= **1.3 lb SO_X/day**

= (0.00282 lb/MMBtu) * (37.4 MMBtu/hr) * (1,248 hr/year)
= **132 lb SO_X/year**

= (132 lb/year) * (4 qtr/year)
= **33 lb SO_X/qtr**

Post Project Potential to Emit (PE2) (C-3953-12-0)				
	Hourly Emissions (lb/hr)	Daily Emissions (lb/day)	Quarterly Emissions (lb/qtr)	Annual Emissions (lb/year)
NO_X	0.41	4.9	128	513
CO	1.38	16.6	432	1,727
VOC	0.16	1.9	50	201
PM_{10}	0.19	2.2	58	233
SO_X	0.11	1.3	33	132

iii. C-3953-13-0 (Diesel IC engine powering fire water pump)

The emissions for the emergency fire pump engine is calculated as follows, and summarized in the table below:

PE_{NOx} = (3.4 g/hp·hr) * (288 hp) ÷ (453.6 g/lb)
= **2.16 lb NO_X/hr**

= (3.4 g/hp·hr) * (288 hp) ÷ (453.6 g/lb) * (24 hr/day)
= **51.8 lb NO_X/day**

= (3.4 g/hp·hr) * (288 hp) ÷ (453.6 g/lb) * (12.5 hr/qtr)
= **27 lb NO_X/qtr**

= (3.4 g/hp·hr) * (288 hp) ÷ (453.6 g/lb) * (50 hr/year)
= **108 lb NO_X/year**

PE_{CO} = (0.447 g/hp·hr) * (288 hp) ÷ (453.6 g/lb)
= **0.28 lb CO/hr**

= (0.447 g/hp·hr) * (288 hp) ÷ (453.6 g/lb * (24 hr/day)
= **6.8 lb CO/day**

= (0.447 g/hp·hr) * (288 hp) ÷ (453.6 g/lb) * (12.5 hr/qtr)
= **4 lb CO/qtr**

= (0.447 g/hp·hr) * (288 hp) ÷ (453.6 g/lb) * (50 hr/year)
= **14 lb CO/year**

PE_{VOC} = (0.38 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb)
= **0.24 lb VOC/hr**

= (0.38 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (24 hr/day)
= **5.8 lb VOC/day**

= (0.38 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (12.5 hr/qtr)
= **3 lb VOC/qtr**

= (0.38 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (50 hr/year)
= **12 lb VOC/year**

PE_{PM10} = (0.059 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb)
= **0.04 lb PM_{10}/hr**

= (0.059 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (24 hr/day)
= **0.9 lb PM_{10}/day**

= (0.059 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (12.5 hr/qtr)
= **0.5 lb PM_{10}/qtr**

= (0.059 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (50 hr/year)
= **1.9 lb PM_{10}/year**

PE_{SOx} = (0.005 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb)
= **0.00 lb SO_X/hr**

= (0.005 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (24 hr/day)
= **0.1 lb SO_X/day**

= (0.005 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (12.5 hr/qtr)
= **0 lb SO_X/qtr**

= (0.005 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (50 hr/year)
= **0 lb SO_X/year**

Post Project Potential to Emit (PE2) (C-3953-13-0)				
	Hourly Emissions (lb/hr)	Daily Emissions (lb/day)	Quarterly Emissions (lb/qtr)	Annual Emissions (lb/year)
NO_X	2.16	51.8	27	108
CO	0.28	6.8	4	14
VOC	0.24	5.8	3	12
PM_{10}	0.04	0.9	0.5	2
SO_X	0.00	0.1	0	0

iv. C-3953-14-0 (Natural gas IC engine powering electrical generator)

The emissions for the emergency IC engine is calculated as follows, and summarized in the table below:

PE_{NOx} = (1.0 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb)
= **1.90 lb NO_X/hr**

= (1.0 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (24 hr/day)
= **45.5 lb NO_X/day**

= (1.0 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (12.5 hr/qtr)
= **24 lb NO_X/qtr**

= (1.0 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (50 hr/year)
= **95 lb NO_X/year**

PE_{CO} = (0.6 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb)
= **1.14 lb CO/hr**

= (0.6 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (24 hr/day)
= **27.3 lb CO/day**

= (0.6 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (12.5 hr/qtr)
= **14 lb CO/qtr**

= (0.6 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (50 hr/year)
= **57 lb CO/year**

PE_{VOC} = (0.33 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb)
= **0.63 lb VOC/hr**

= (0.33 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (24 hr/day)
= **15.0 lb VOC/day**

= (0.33 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (12.5 hr/qtr)
= **8 lb VOC/qtr**

= (0.33 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (50 hr/year)
= **31 lb VOC/year**

PE_{PM10} = (0.034 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb)
= **0.06 lb PM_{10}/hr**

= (0.034 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (24 hr/day)
= **1.5 lb PM_{10}/day**

= (0.034 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (12.5 hr/qtr)
= **1 lb PM_{10}/qtr**

= (0.034 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (50 hr/year)
= **3 lb PM_{10}/year**

PE_{SOx} = (0.0094 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb)
= **0.02 lb SO_X/hr**

= (0.0094 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (24 hr/day)
= **0.4 lb SO_X/day**

= (0.0094 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (12.5 hr/qtr)
= **0 lb SO_X/qtr**

= (0.0094 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (50 hr/year)
= **1 lb SO_X/year**

Post Project Potential to Emit (PE2) (C-3953-14-0)				
	Hourly Emissions (lb/hr)	Daily Emissions (lb/day)	Quarterly Emissions (lb/qtr)	Annual Emissions (lb/year)
NO_X	1.90	45.5	24	95
CO	1.14	27.3	14	57
VOC	0.63	15.0	8	31
PM_{10}	0.06	1.5	1	3
SO_X	0.02	0.4	0	1

3. Pre-Project Stationary Source Potential to Emit (SSPE1)

Pursuant to Section 4.9 of District Rule 2201, the Pre-project Stationary Source Potential to Emit (SSPE1) is the Potential to Emit (PE) from all units with valid Authorities to Construct (ATC) or Permits to Operate (PTO) at the Stationary Source and the quantity of emission reduction credits (ERC) which have been banked since September 19, 1991 for Actual Emissions Reductions that have occurred at the source, and which have not been used on-site. Since this is a new facility, there are no valid ATCs, PTOs, or ERCs at the Stationary Source; therefore, the SSPE1 will be equal to zero.

4. Post-Project Stationary Source Potential to Emit (SSPE2)

Pursuant to Section 4.10 of District Rule 2201, the Post Project Stationary Source Potential to Emit (SSPE2) is the Potential to Emit (PE) from all units with valid Authorities to Construct (ATC) or Permits to Operate (PTO) at the Stationary Source and the quantity of emission reduction credits (ERC) which have been banked since September 19, 1991 for Actual Emissions Reductions that have occurred at the source, and which have not been used on-site.

Post-project Stationary Source Potential to Emit [SSPE2] (lb/year)						
Permit Unit	NO_X	CO	VOC	PM_{10}	SO_X	NH_3
C-3953-10-0	143,951	601,810	34,489	80,656	16,694	219,972
C-3953-11-0	143,951	601,810	34,489	80,656	16,694	219,972
C-3953-12-0	513	1,727	201	233	132	0
C-3953-13-0	108	14	12	2	0	0
C-3953-14-0	95	57	31	3	1	0
Post-project SSPE (SSPE2)	**288,618**	**1,205,418**	**69,222**	**161,550**	**33,521**	**439,944**

5. Major Source Determination

Pursuant to Section 3.24 of District Rule 2201, a major source is a stationary source with post-project emissions or a Post-project Stationary Source Potential to Emit (SSPE2), equal to or exceeding one or more of the following threshold values.

Major Source Determination					
	NO_X (lb/year)	CO (lb/year)	VOC (lb/year)	PM_{10} (lb/year)	SO_X (lb/year)
Post-project SSPE (SSPE2)	288,618	1,205,418	69,222	161,550	33,521
Major Source Threshold	50,000	200,000	50,000	140,000	140,000
Major Source?	Yes	Yes	Yes	Yes	No

6. Annual Baseline Emissions (BE)

Per District Rule 2201, Section 3.7, the baseline emissions, for a given pollutant, shall be equal to the pre-project potential to emit for:

- Any emission unit located at a non-major source,
- Any highly utilized emission unit, located at a major source,
- Any fully-offset emission unit, located at a major source, or
- Any clean emission unit located at a major source

otherwise,

BE = Historic Actual Emissions (HAE), calculated pursuant to Section 3.22 of District Rule 2201

As shown above, this facility will be a major source for NO_X, CO, VOC, and PM_{10} emissions after this project. However, since the units in this project are all new emissions units, there are no historical actual emissions or pre-project potential to emit. Therefore, the baseline NO_X, CO, VOC, PM_{10} and SO_X emissions will be set equal to the following:

BE = 0 lb/year

7. Major Modification

Major Modification is defined in 40 CFR Part 51.165 as "*any physical change in or change in the method of operation of a major stationary source that would result in a significant net emissions increase of any pollutant subject to regulation under the Act.*"

Since this is a new facility, this project cannot be considered a Major Modification.

8. Federal Major Modification

As shown above, this project does not constitute a Major Modification. Therefore, in accordance with District Rule 2201, Section 3.17, this project does not constitute a Federal Major Modification and no further discussion is required.

VIII. COMPLIANCE:

Rule 1080 Stack Monitoring

This Rule grants the APCO the authority to request the installation and use of continuous emissions monitors (CEMs), and specifies performance standards for the equipment and administrative requirements for recordkeeping, reporting, and notification.

i. C-3953-10-0 and C-3953-11-0 (Turbines)

The two CTGs will be equipped with operational CEMs for NO_X, CO, and O_2. Provisions included in the operating permit are consistent with the requirements of this Rule. Compliance with the requirements of this Rule is anticipated.

Proposed Rule 1080 Conditions:

- The owner or operator shall install, certify, maintain, operate and quality-assure a Continuous Emission Monitoring System (CEMS) which continuously measures and records the exhaust gas NO_X, CO and O_2 concentrations. Continuous emissions monitor(s) shall be capable of monitoring emissions during normal operating conditions, and during startups and shutdowns, provided the CEMS passes the relative accuracy requirement for startups and shutdowns specified herein. If relative accuracy of CEMS cannot be demonstrated during startup conditions, CEMS results during startup and shutdown events shall be replaced with startup emission rates obtained from source testing to determine compliance with emission limits contained in this document. [District Rules 1080 and 4703 and 40 CFR 60.4340(b)(1)]

- The CEMS shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period or shall meet equivalent specifications established by mutual agreement of the District, the ARB and the EPA. [District Rule 1080 and 40 CFR 60.4345(b)]

- The NO_X, CO and O_2 CEMS shall meet the requirements in 40 CFR 60, Appendix F Procedure 1 and Part 60, Appendix B Performance Specification 2 (PS 2), or shall meet equivalent specifications established by mutual agreement of the District, the ARB, and the EPA. [District Rule 1080 and 40 CFR 60.4345(a)]

- Audits of continuous emission monitors shall be conducted quarterly, except during quarters in which relative accuracy and compliance source testing are both performed, in accordance with EPA guidelines. The District shall be notified prior to completion of the audits. Audit reports shall be submitted along with quarterly compliance reports to the District. [District Rule 1080]

- The owner/operator shall perform a relative accuracy test audit (RATA) for NO_X, CO and O_2 as specified by 40 CFR Part 60, Appendix F, 5.11, at least once every four calendar quarters. The permittee shall comply with the applicable requirements for quality assurance testing and maintenance of the continuous emission monitor equipment in accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F. [District Rule 1080]

- APCO or an authorized representative shall be allowed to inspect, as determined to be necessary, the required monitoring devices to ensure that such devices are functioning properly. [District Rule 1080]

- Results of the CEM system shall be averaged over a one hour period for NO_X emissions and a three hour period for CO emissions using consecutive 15-minute sampling periods in accordance with all applicable requirements of CFR 60.13. [District Rule 4703 and 40 CFR 60.13]

- Results of continuous emissions monitoring shall be reduced according to the procedures established in 40 CFR, Part 51, Appendix P, paragraphs 5.0 through 5.3.3, or by other methods deemed equivalent by mutual agreement with the District, the ARB, and the EPA. [District Rule 1080]

- The owner or operator shall, upon written notice from the APCO, provide a summary of the data obtained from the CEM systems. This summary shall be in the form and the manner prescribed by the APCO. [District Rule 1080]

- The facility shall install and maintain equipment, facilities, and systems compatible with the District's CEM data polling software system and shall make CEM data available to the District's automated polling system on a daily basis. [District Rule 1080]

- Upon notice by the District that the facility's CEM system is not providing polling data, the facility may continue to operate without providing automated data for a maximum of 30 days per calendar year provided the CEM data is sent to the District by a District-approved alternative method. [District Rule 1080]

- The permittee shall maintain the following records: the date, time and duration of any malfunction of the continuous monitoring equipment; dates of performance testing; dates of evaluations, calibrations, checks, and adjustments of the continuous monitoring equipment; date and time period which a continuous monitoring system or monitoring device was inoperative. [District Rules 1080 and 2201 and 40 CFR 60.8(d)]

- The owner or operator shall submit a written report of CEM operations for each calendar quarter to the APCO. The report is due on the 30th day following the end of the calendar quarter and shall include the following: Time intervals, data and magnitude of excess NOx emissions, nature and the cause of excess (if known), corrective actions taken and preventive measures adopted; Averaging period used for data reporting corresponding to the averaging period specified in the emission test period used to determine compliance with an emission standard; Applicable time and date of each period during which the CEM was inoperative (monitor downtime), except for zero and span checks, and the nature of system repairs and adjustments; A negative declaration when no excess emissions occurred. [District Rule 1080 and 40 CFR 60.4375(a) and 60.4395]

ii. C-3953-12 (Boiler)

The boiler will be equipped with operational CEMs for NO_X, CO, and O_2. Provisions included in the operating permit are consistent with the requirements of this Rule. Compliance with the requirements of this Rule is anticipated.

Proposed Rule 1080 Conditions:

- {1832} The exhaust stack shall be equipped with a continuous emissions monitor (CEM) for NOx, CO, and O2. The CEM shall meet the requirements of 40 CFR parts 60 and 75 and shall be capable of monitoring emissions during startups and shutdowns as well as during normal operating conditions. [District Rules 2201 and 1080]

- {1833} The facility shall install and maintain equipment, facilities, and systems compatible with the District's CEM data polling software system and shall make CEM data available to the District's automated polling system on a daily basis. [District Rule 1080]

- {1834} Upon notice by the District that the facility's CEM system is not providing polling data, the facility may continue to operate without providing automated data for a maximum of 30 days per calendar year provided the CEM data is sent to the District by a District-approved alternative method. [District Rule 1080]

- {1836} Results of continuous emissions monitoring shall be reduced according to the procedure established in 40 CFR, Part 51, Appendix P, paragraphs 5.0 through 5.3.3, or by other methods deemed equivalent by mutual agreement with the District, the ARB, and the EPA. [District Rule 1080]

- {1837} Audits of continuous emission monitors shall be conducted quarterly, except during quarters in which relative accuracy and total accuracy testing is performed, in accordance with EPA guidelines. The District shall be notified prior to completion of the audits. Audit reports shall be submitted along with quarterly compliance reports to the District. [District Rule 1080]

- {1838} The owner/operator shall perform a relative accuracy test audit (RATA) as specified by 40 CFR Part 60, Appendix F, 5.11, at least once every four calendar quarters. The permittee shall comply with the applicable requirements for quality assurance testing and maintenance of the continuous emission monitor equipment in accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F. [District Rule 1080]

- {1839} The permittee shall submit a written report to the APCO for each calendar quarter, within 30 days of the end of the quarter, including: time intervals, data and magnitude of excess emissions, nature and cause of excess emissions (if known), corrective actions taken and preventive measures adopted; averaging period used for data reporting shall correspond to the averaging period for each respective emission standard; applicable time and date of each period during which the CEM was inoperative (except for zero and span checks) and the nature of system repairs and adjustments; and a negative declaration when no excess emissions occurred. [District Rule 1080]

Rule 1081 Source Sampling

This Rule requires adequate and safe facilities for use in sampling to determine compliance with emissions limits, and specifies methods and procedures for source testing and sample collection.

i. C-3953-10-0 and C-3953-11-0 (Turbines)

The requirements of this Rule will be included in the operating permits. Compliance with this Rule is anticipated.

Proposed Rule 1081 Conditions:

- The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Emission Monitoring and Testing. [District Rule 1081]

- Source testing to measure startup NOx, CO, and VOC mass emission rates shall be conducted for one of the gas turbines (C-3953-10 or C-3953-11) prior to the end of the commissioning period and at least once every seven years thereafter. CEM relative accuracy shall be determined during startup source testing in accordance with 40 CFR 60, Appendix B. [District Rule 1081]

- Source testing (with and without duct burner firing) to measure the NOx, CO, and VOC emission rates (lb/hr and ppmvd @ 15% O2) shall be conducted within 60 days after the end of the commissioning period and at least once every twelve months thereafter. [District Rules 1081 and 4703]

- Source testing (with and without duct burner firing) to measure the PM10 emission rate (lb/hr) and the ammonia emission rate shall be conducted within 60 days after the end of the commissioning period and at least once every twelve months thereafter. [District Rule 1081]

- Compliance with natural gas sulfur content limit shall be demonstrated within 60 days after the end of the commissioning period and weekly thereafter. After demonstrating compliance with the fuel sulfur content limit for 8 consecutive weeks for a fuel source, then the testing frequency shall not be less than monthly. If a test shows noncompliance with the sulfur content requirement, the source must return to weekly testing until eight consecutive weeks show compliance. [District Rules 1081, 2540, and 4001]

- Demonstration of compliance with the annual average sulfur content limit shall be demonstrated by a 12 month rolling average of the sulfur content either (i) documented in a valid purchase contract, a supplier certification, a tariff sheet or transportation contract or (ii) tested using ASTM Methods D1072, D3246, D4084, D4468, D4810, D6228, D6667 or Gas Processors Association Standard 2377. [District Rules 1081 and 2201]

- Compliance demonstration (source testing) shall be District witnessed, or authorized and samples shall be collected by a California Air Resources Board certified testing laboratory. Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified 30 days prior to any compliance source test, and a source test plan must be submitted for approval 15 days prior to testing. The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

- The following test methods shall be used: NO_X - EPA Method 7E or 20; CO - EPA Method 10 or 10B; VOC - EPA Method 18 or 25; PM10 - EPA Method 5 (front half and back half) or 201 and 202a; ammonia - BAAQMD ST-1B; and O_2 - EPA Method 3, 3A, or 20. EPA approved alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4703 and 40 CFR 60.4400(1)(i)]

ii. C-3953-12-0 (Boiler)

The requirements of this Rule will be included in the operating permit. Compliance with this Rule is anticipated.

Proposed Rule 1081 Conditions:

- The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Emission Monitoring and Testing. [District Rule 1081]

- {109} Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]

- {110} The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

Rule 1100 Equipment Breakdown

This Rule defines a breakdown condition and the procedures to follow if one occurs. The corrective action, the issuance of an emergency variance, and the reporting requirements are also specified.

i. C-3953-10-0 and C-3953-11-0 (Turbines)

The requirements of this Rule will be included in the operating permits. Compliance with this Rule is anticipated.

Proposed Rule 1100 Conditions:

- Permittee shall notify the District of any breakdown condition as soon as reasonably possible, but no later than one hour after its detection, unless the owner or operator demonstrates to the District's satisfaction that the longer reporting period was necessary. [District Rule 1100, 6.1]

- The District shall be notified in writing within ten days following the correction of any breakdown condition. The breakdown notification shall include a description of the equipment malfunction or failure, the date and cause of the initial failure, the estimated emissions in excess of those allowed, and the methods utilized to restore normal operations. [District Rule 1100, 7.0]

Rule 2010 Permits Required

This Rule requires any person building, altering, or replacing any operation, article, machine, equipment, or other contrivance, the use of which may cause the issuance of air contaminants, to first obtain authorization from the District in the form of an ATC. By the submission of an ATC application, Avenal Power Center, LLC is complying with the requirements of this Rule.

Rule 2201 New and Modified Stationary Source Review Rule

A. BACT:

1. BACT Applicability

BACT requirements are triggered on a pollutant-by-pollutant basis and on an emissions unit-by-emissions unit basis for the following*:

a. Any new emissions unit with a potential to emit exceeding two pounds per day,
b. The relocation from one Stationary Source to another of an existing emissions unit with a potential to emit exceeding two pounds per day,
c. Modifications to an existing emissions unit with a valid Permit to Operate resulting in an AIPE exceeding two pounds per day, and/or
d. Any new or modified emissions unit, in a stationary source project, which results in a Major Modification.

*Except for CO emissions from a new or modified emissions unit at a Stationary Source with an SSPE2 of less than 200,000 pounds per year of CO.

i. C-3953-10-0 and C-3953-11-0 (Turbines)

As seen in Section VII.C.2.b of this evaluation, the applicant is proposing to install two new combustion turbine generators with PEs greater than 2 lb/day for NO_X, CO, VOC, PM_{10}, and SO_X. BACT is triggered for NO_X, CO, VOC, PM_{10}, and SO_X criteria pollutants since the PEs are greater than 2 lbs/day, and since the SSPE2 for CO is greater than 200,000 lbs/year, as demonstrated in Section VII.C.5 of this document.

The PE of ammonia is greater than two pounds per day for the two CTGs. However, the ammonia emissions are intrinsic to the operation of the SCR system, which is BACT for NO_X. The emissions from a control device that is determined by the District to be BACT are not subject to BACT.

ii. C-3953-12-0 (Boiler)

As seen in Section VII.C.2 of this evaluation, the applicant is proposing to install a new boiler with a PE greater than 2 lb/day for NO_X, CO, VOC, PM_{10}, and SO_X. BACT is triggered for NO_X, CO, VOC, and PM_{10} criteria pollutants since the PEs are greater than 2 lbs/day, and since the SSPE2 for CO is greater than 200,000 lbs/year, as demonstrated in Section VII.C.5 of this document.

iii. C-3953-13-0 (Diesel IC engine powering fire water pump)

As seen in Section VII.C.2 of this evaluation, the applicant is proposing to install a new diesel-fired IC engine (fire pump) with a PE greater than 2 lb/day for NO_X, CO, and VOC. BACT is triggered for NO_X, CO, and VOC criteria pollutants since the PEs are greater than 2 lbs/day, and since the SSPE2 for CO is greater than 200,000 lbs/year, as demonstrated in Section VII.C.5 of this document.

iv. C-3953-14-0 (Natural gas IC engine powering electrical generator)

As seen in Section VII.C.2 of this evaluation, the applicant is proposing to install a new natural gas-fired IC engine (generator) with a PE greater than 2 lb/day for NO_X, CO, and VOC. BACT is triggered for NO_X, CO, and VOC criteria pollutants since the PEs are greater than 2 lbs/day, and since the SSPE2 for CO is greater than 200,000 lbs/year, as demonstrated in Section VII.C.5 of this document.

2. BACT Guidance

The District BACT Clearinghouse was created to assist applicants in selecting appropriate control technology for new and modified sources, and to assist the District staff in conducting the necessary BACT analysis. The Clearinghouse will include, for various class and category of sources, available control technologies and methods that meet one or more of the following conditions:

- Have been achieved in practice for such emissions unit and class of source; or
- Are contained in any SIP approved by the EPA for such emissions unit category and class of source; or
- Are any other emission limitation or control technique, including process and equipment changes of basic or control equipment, found to be technologically feasible for such class or category of sources or for a specific source.

Attachment E will include the BACT Guidelines from the BACT Clearinghouse applicable to the new emissions units associated with this project.

i. C-3953-10-0 and C-3953-11-0 (Turbines)

BACT Guideline 3.4.2 is applicable to the two combustion turbine generator installations [Gas Fired Turbine = or > 50 MW, Uniform Load, with Heat Recovery].

ii. C-3953-12-0 (Boiler)

BACT Guideline 1.1.2 is applicable to the 37.4 MMBtu/hr boiler. [Boiler - > 20 MMBtu/hr, Natural gas-fired, base-loaded or with small load swings.]

iii. C-3953-13-0 (Diesel IC engine powering fire water pump)

BACT Guideline 3.1.4, applies to the diesel-fired emergency IC engine powering a fire pump. [Emergency Diesel I.C. Engine Driving a Fire Pump]

iv. C-3953-14-0 (Natural gas IC engine powering electrical generator)

BACT Guideline 3.1.8, applies to the natural gas-fired emergency IC engine powering an electrical generator. [Emergency Gas-Fired I.C. Engine > or = 250 hp, Lean Burn]

3. Top-Down Best Available Control Technology (BACT) Analysis

Per Permit Services Policies and Procedures for BACT, a Top-Down BACT analysis shall be performed as a part of the application review for each application subject to the BACT requirements pursuant to the District's NSR Rule.

For Permit Units C-3953-10-0 and -11-0 see Attachment F.

For Permit Unit C-3953-12-0 see Attachment F.

For Permit Unit C-3953-13-0 see Attachment F.

For Permit Unit C-3953-14-0 see Attachment F.

4. BACT Summary:

i. C-3953-10-0 and C-3953-11-0 (Turbines)

BACT has been satisfied by the following:

NO_X: 2.0 ppmv @ 15% O_2 (1-hour rolling average, except during startup/shutdown) with Dry Low NO_X Combustors, SCR with ammonia injection and natural gas fuel.

CO: 2.0 ppmv @ 15% O_2 (3-hour rolling average, except during startup/shutdown) with an Oxidation Catalyst and natural gas fuel.

VOC: 1.5 ppmv @ 15% O_2 (without duct burner firing; 3-hour rolling average).
2.0 ppmv @ 15% O_2 (with duct burner firing; 3-hr rolling average).

PM_{10}: Air inlet filter cooler, lube oil vent coalescer, and natural gas fuel

SO_X: PUC regulated natural gas with a sulfur content of 1.0 gr/100 scf or less

ii. C-3953-12-0 (Boiler)

BACT has been satisfied by the following:

NO_X: 9.0 ppmv @ 15% O_2 with Ultra Low NO_X burners and natural gas fuel.

CO: Natural gas fuel.

VOC: Natural gas fuel.

PM_{10}: Natural gas fuel.

SO_X: Natural gas fuel.

iii. C-3953-13-0 (Diesel IC engine powering fire water pump)

BACT has been satisfied by the following:

NO_X: Certified NO_X emissions of 6.9 g/hp·hr or less

CO: No CO control. Any add on CO control device would void the Underwriters Laboratory (UL) certification.

VOC: No VOC control. Any add on VOC control device would void the Underwriters Laboratory (UL) certification.

iv. C-3953-14-0 (Natural gas IC engine powering electrical generator)

BACT has been satisfied by the following:

NO_X: = or < 1.0 g/bhp-hr (lean burn natural gas fired engine, or equal)

CO: 90% control efficiency (oxidation catalyst, or equal)

VOC: 90% control efficiency (oxidation catalyst, or equal)

Therefore, the following condition will be listed on the DOC to ensure compliance:

- {3492} This IC engine shall be equipped with a three-way catalyst. [District Rule 2201]

C. Offsets:

1. Offset Applicability:

Pursuant to Section 4.5.3, offset requirements shall be triggered on a pollutant by pollutant basis and shall be required if the Post-project Stationary Source Potential to Emit (SSPE2) equals to or exceeds emissions of 20,000 lbs/year for NO_X and VOC, 200,000 lbs/year for CO, 54,750 lbs/year for SO_X and 29,200 lbs/year for PM_{10}. As seen in the table below, the facility's SSPE2 is greater than the offset thresholds for NO_X, CO, VOC, PM_{10}, and SO_X emissions. Therefore, offset calculations are necessary.

Offset Determination					
	NO_X (lb/year)	CO (lb/year)	VOC (lb/year)	PM_{10} (lb/year)	SO_X (lb/year)
Post-project SSPE (SSPE2)	288,618	1,205,418	69,222	161,550	33,521
Offset Threshold	20,000	200,000	20,000	29,200	54,750
Offsets Required?	Yes	Yes	Yes	Yes	No

2. Quantity of Offsets Required:

Per District Rule 2201, Section 4.6.1, emission offsets shall not be required for increases in carbon monoxide in attainment areas if the applicant demonstrates to the satisfaction of the APCO, that the Ambient Air Quality Standards are not violated in the areas to be affected, and such emissions will be consistent with Reasonable Further Progress, and will not cause or contribute to a violation of Ambient Air Quality Standards.

As shown in section VIII.G below, the increase in CO emissions associated with this stationary source project does not cause or contribute to a violation of Ambient Air Quality Standards. CO emissions are not addressed in any Reasonable Further Progress Plans. Therefore, this stationary source project qualifies for the offset exemption listed in Section 4.6.1.

Per Sections 4.7.2 and 4.7.3, the quantity of offsets in pounds per year for NO_X, CO, VOC, and PM_{10} is calculated as follows for sources with an SSPE1 less than the offset threshold levels before implementing the project being evaluated.

Offsets Required (lb/year) = ([SSPE2 – Offset Threshold] + ICCE) x DOR, for all new or modified emissions units in the project,

Where,
SSPE2 = Post Project Facility Potential to Emit, (lb/year)
ICCE = Increase in Cargo Carrier Emissions, (lb/year)
DOR = Distance Offset Ratio, determined pursuant to Section 4.8

Per Section 4.6.2, emergency equipment that is used exclusively as emergency standby equipment for electrical power generation or any other emergency equipment as approved by the APCO that does not operate more than 200 hours per year of non-emergency purposes and is not used pursuant to voluntary arrangements with a power supplier to curtail power, is exempt from providing emission offsets. Therefore, permit units C-3953-13-0 and C-3953-14-0 will be exempt from providing offsets and the emissions associated with these permit units contributing to the SSPE2 should be removed prior to calculating actual offset amounts.

Offset = ([SSPE2 – Emergency Equipment - Offset Threshold] + ICCE) x DOR, for all new or modified emissions units in the project,

<u>NO_X Offset Calculations:</u>

NO_X SSPE2 = 288,618 lb/year
C-3953-13-0 (NO_X) = 108 lb/year
C-3953-14-0 (NO_X) = 95 lb/year
NO_X offset threshold = 20,000 lb/year

Offsets = [288,618 – (108) – (95) – 20,000]
= 268,415 lb/year ∗ DOR

Calculating the appropriate quarterly emissions to be offset is as follows:

Offsets = (268,415 lb/year ÷ 4 qtr/year) ∗ DOR
= 67,103.75 lb/qtr ∗ DOR

$PE_{1st\ Qtr}$ = 67,103.75 lbs of NO_X ∗ DOR
$PE_{2nd\ Qtr}$ = 67,103.75 lbs of NO_X ∗ DOR
$PE_{3rd\ Qtr}$ = 67,103.75 lbs of NO_X ∗ DOR
$PE_{4th\ Qtr}$ = 67,103.75 lbs of NO_X ∗ DOR

Pursuant to Section 4.8 of District Rule 2201, the distance offset ratio shall be 1.0:1 if the emission offsets originated at the same Stationary Source as the new or modified emissions unit; 1.2.1 for Non-Major Sources if the emission offsets originated within 15 miles of the new or modified emissions unit's Stationary Source; 1.3.1 for Major Sources if the emission offsets originated within 15 miles of the new or modified emissions unit's

Stationary Source; or 1.5:1 if the emission offsets originated 15 miles or more from the new or modified emissions unit's Stationary Source.

Assuming a worst case offset ratio of 1.5:1, the amount of NO_X ERC's that need to be withdrawn is:

Offsets Required = 268,415 lb-NO_X/year x 1.5
Offsets Required = 402,623 lb-NO_X/year

Calculating the appropriate quarterly emissions to be offset is as follows:

Quantity of Offsets Required					
	1st Quarter (lb/qtr)	2nd Quarter (lb/qtr)	3rd Quarter (lb/qtr)	4th Quarter (lb/qtr)	Total (lb/year)
NO_X	100,655	100,656	100,656	100,656	402,623

The applicant has stated that the facility plans to use ERC certificates C-899-2, C-902-2, N-720-2, N-722-2, N-726-2, N-728-2, S-2814-2, and S-2321-2 to offset the increases in NO_X emissions associated with this project. The above Certificates have available quarterly NO_X credits as follows:

Offset Proposal					
	1st Quarter (lb/qtr)	2nd Quarter (lb/qtr)	3rd Quarter (lb/qtr)	4th Quarter (lb/qtr)	**Total (lb/year)**
ERC #C-899-2	2,243	2,243	2,243	2,243	**8,972**
ERC #C-902-2	13,879	6,131	1,086	8,539	**29,635**
ERC #N-720-2	0	9	1,255	437	**1,701**
ERC #N-722-2	0	1,166	88,317	1,422	**90,905**
ERC #N-726-2	0	0	4,728	0	**4,728**
ERC #N-728-2	10,542	3,731	2,487	5,171	**21,931**
ERC #S-2814-2	6,121	13,869	18,914	11,461	**50,365**
ERC #S-2321-2*	51,000	51,000	51,000	51,000	**204,000**
Total	**83,784**	**78,147**	**170,027**	**80,269**	**412,227**

*ERC certificate split from this ERC.

Project NO_X offset requirements

The applicant states that NO_X ERC certificates C-899-2, C-902-2, N-720-2, N-722-2, N-726-2, N-728-2, S-2814-2, and S-2321-2 will be utilized to supply the NO_X offset requirements.

Per Rule 2201 Section 4.13.8, Actual Emission Reductions (i.e. ERCs) that occurred from April through November (i.e. 2nd and 3rd Quarter), inclusive, may be used to offset increases in NO_X or VOC during any period of the year. Since 3rd quarter NO_X ERCs will be used to offset NO_X emissions, the above applies to the NO_X ERCs.

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
NO_X Emissions to be offset: (at a 1.5:1 DOR):	100,655	100,656	100,656	100,656
Available ERCs from certificates C-899-2, C-902-2, N-720-2, N-722-2, N-726-2, N-728-2, S-2814-2, and S-2321-2*:	83,784	78,147	170,027	80,269
3rd qtr. ERCs applied to 1st qtr. ERCs:	16,871	0	-16,871	0
3rd qtr. ERCs applied to 2nd qtr. ERCs:	0	22,509	-22,509	0
3rd qtr. ERCs applied to 4th qtr. ERCs:	0	0	-20,387	20,387
Remaining ERCs from certificates S-2321-2:	0	0	9,604	0
Remaining NO_X emissions to be offset (at a 1.5:1 DOR):	0	0	0	0

As seen above, the facility has sufficient credits to fully offset the quarterly NO_X emissions increases associated with this project.

<u>VOC Offset Calculations:</u>

VOC SSPE2 = 69,222 lb/year
C-3953-13-0 (VOC) = 12 lb/year
C-3953-14-0 (VOC) = 31 lb/year
VOC offset threshold = 20,000 lb/year

Offsets = [69,222 – (12) – (31) – 20,000]
= 49,179 lb/year ∗ DOR

Calculating the appropriate quarterly emissions to be offset is as follows:

Offsets = (49,179 lb/year ÷ 4 qtr/year) ∗ DOR
= 12,294.75 lb/qtr ∗ offset ratio

$PE_{1st\ Qtr}$ = 12,294.75 lbs of VOC ∗ DOR
$PE_{2nd\ Qtr}$ = 12,294.75 lbs of VOC ∗ DOR
$PE_{3rd\ Qtr}$ = 12,294.75 lbs of VOC ∗ DOR
$PE_{4th\ Qtr}$ = 12,294.75 lbs of VOC ∗ DOR

Pursuant to Section 4.8 of District Rule 2201, the distance offset ratio shall be 1.0:1 if the emission offsets originated at the same Stationary Source as the new or modified emissions unit; 1.2.1 for Non-Major Sources if the emission offsets originated within 15 miles of the new or modified emissions unit's Stationary Source; 1.3.1 for Major Sources if the emission offsets originated within 15 miles of the new or modified emissions unit's Stationary Source; or 1.5:1 if the emission offsets originated 15 miles or more from the new or modified emissions unit's Stationary Source.

Assuming a worst case offset ratio of 1.5:1, the amount of VOC ERC's that need to be withdrawn is:

$PE_{1st\ Qtr}$ = 12,294.75 lbs of VOC ∗ 1.5 = 18,442 lbs
$PE_{2nd\ Qtr}$ = 12,294.75 lbs of VOC ∗ 1.5 = 18,442 lbs
$PE_{3rd\ Qtr}$ = 12,294.75 lbs of VOC ∗ 1.5 = 18,442 lbs
$PE_{4th\ Qtr}$ = 12,294.75 lbs of VOC ∗ 1.5 = 18,442 lbs

Calculating the appropriate quarterly emissions to be offset is as follows:

Quantity of Offsets Required					
	1st Quarter (lb/qtr)	2nd Quarter (lb/qtr)	3rd Quarter (lb/qtr)	4th Quarter (lb/qtr)	Total (lb/year)
VOC	18,442	18,442	18,442	18,442	73,769

The applicant has stated that the facility plans to use ERC certificates C-897-1, C-898-1, N-724-1, N-725-1, S-2812-1, S-2813-1, and S-2817-1 to offset the increases in VOC emissions associated with this project. The above Certificates have available quarterly VOC credits as follows:

Offset Proposal					
	1st Quarter (lb/qtr)	2nd Quarter (lb/qtr)	3rd Quarter (lb/qtr)	4th Quarter (lb/qtr)	**Total (lb/year)**
ERC #C-897-1	45	45	45	45	**180**
ERC #C-898-1	5,480	6,496	4,696	6,616	**23,288**
ERC #N-724-1	0	0	241	0	**241**
ERC #N-725-1	0	0	709	0	**709**
ERC #S-2812-1	31,432	31,424	31,417	31,417	**125,690**
ERC #S-2813-1	12,500	12,500	12,500	12,500	**50,000**
ERC #S-2817-1	11,431	11,424	11,417	11,417	**45,689**
Total	**60,887**	**61,887**	**61,022**	**61,991**	**245,787**

Project VOC offset requirements

The applicant states that NO_X ERC certificates C-897-1, C-898-1, N-724-1, N-725-1, S-2812-1, S-2813-1, and S-2817-1 will be utilized to supply the VOC offset requirements.

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
VOC Emissions to be offset: (at a 1.5:1 DOR):	18,442	18,442	18,442	18,442
Available ERCs from certificates C-897-1, C-898-1, N-724-1, N-725-1,	5,525	6,541	5,691	6,661
Remaining VOC emissions to be offset (at a 1.5:1 DOR):	12,917	11,901	12,751	11,781
VOC Emissions to be offset: (at a 1.5:1 DOR):	12,917	11,901	12,751	11,781
Available ERCs from certificates S-2812-1, S-2813-1, and S-2817-1	55,363	55,348	55,334	55,334
Remaining ERCs from certificates S-2812-1, S-2813-1, and S-2817-1:	42,446	43,447	42,583	43,553
Remaining VOC emissions to be offset (at a 1.5:1 DOR):	0	0	0	0

As seen above, the facility has sufficient credits to fully offset the quarterly VOC emissions increases associated with this project.

PM_{10} Offset Calculations:

PM_{10} SSPE2 = 161,545 lb/year
C-3953-13-0 (PM_{10}) = 2 lb/year
C-3953-14-0 (PM_{10}) = 3 lb/year
PM_{10} Offset threshold = 29,200 lb/year

Offsets = [(161,545 – (2) – (3) - 29,200 + 0) x DOR]
= 132,340 lb/year x DOR

Calculating the appropriate quarterly emissions to be offset is as follows (in lb/qtr):

Offsets = (132,340 lb/year ÷ 4 qtr/year) ∗ DOR
= 33,085 lb/qtr ∗ offset ratio

$PE_{1st\ Qtr}$ = 33,085 lbs of PM_{10} * DOR
$PE_{2nd\ Qtr}$ = 33,085 lbs of PM_{10} * DOR
$PE_{3rd\ Qtr}$ = 33,085 lbs of PM_{10} * DOR
$PE_{4th\ Qtr}$ = 33,085 lbs of PM_{10} * DOR

The applicant is proposing to use ERC Certificates C-894-4, N-721-4, N-723-4, N-762-5, S-2788-5, S-2789-5, S-2790-5, and 2791-5 which have an original site of reduction greater than 15 miles from the location of this project. Therefore, a distance offset ratio of 1.5:1 is applicable and the amount of PM_{10} ERCs that need to be withdrawn is:

Offsets Required (lb/year) = 132,340 lb/year x 1.5
= 198,510 lb/year

Calculating the appropriate quarterly emissions to be offset is as follows (in lb/qtr):

Quantity of Offsets Required					
	1st Quarter (lb/qtr)	2nd Quarter (lb/qtr)	3rd Quarter (lb/qtr)	4th Quarter (lb/qtr)	Total (lb/year)
PM_{10}	49,628	49,627	49,627	49,628	198,510

The applicant has stated that the facility plans to use ERC certificates C-894-4, N-721-4, N-723-4, N-762-5, S-2788-5, S-2789-5, S-2790-5, and 2791-5 to offset the increases in PM_{10} emissions associated with this project. The applicant has purchased the following quarterly amounts of the above certificates:

Offset Proposal					
	1st Quarter (lb/qtr)	2nd Quarter (lb/qtr)	3rd Quarter (lb/qtr)	4th Quarter (lb/qtr)	**Total (lb/year)**
ERC #C-896-4	80	80	80	80	**320**
ERC #N-721-4	0	0	3,215	0	**3,215**
ERC #N-723-4	0	0	985	0	**985**
ERC #S-2791-5	92,179	23,666	69,157	96,288	**281,290**
ERC #S-2790-5	12,862	491	0	8,499	**21,852**
ERC #S-2789-5	6	14	12	8	**40**
ERC #S-2788-5	5	7	3	6	**21**
ERC #N-762-5	21,000	21,000	21,000	21,000	**84,000**
Total	**126,131**	**45,256**	**94,449**	**125,877**	**391,723**

Project PM_{10} offset requirements

The applicant states either PM_{10} ERC certificates C-894-4, N-721-4, N-723-4, N-762-5, S-2788-5, S-2789-5, S-2790-5, and 2791-5 will be utilized to supply the PM_{10} offset requirements.

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
PM_{10} Emissions to be offset: (at a 1.5:1 ratio):	49,630	49,629	49,629	49,630
Available ERCs from certificates C-896-4, N-721-4, and N-723-4:	80	80	4,280	80
ERCs applied from certificates C-896-4, N-721-4, and N-723-4 fully withdrawn as certificates C-896-4, N-721-4, and N-723-4:	-80	-80	-4,280	-80
Remaining ERCs from certificate C-896-4, N-721-4, and N-723-4:	0	0	0	0
Remaining PM_{10} emissions to be offset (at a 1.5:1 ratio):	49,550	49,549	45,349	49,550

Per Rule 2201 Section 4.13.3.2, interpollutant offsets between PM_{10} and PM_{10} precursors (i.e. SO_X) may be allowed. The applicant is proposing to use interpollutant offsets SO_X for PM_{10} at an interpollutant ratio of 1.0:1 (see Attachment H). Per Rule 2201 Section 4.13.7, Actual Emission Reductions (i.e. ERCs) that occurred from October through March (i.e. 1st and 4th Quarter), inclusive, may be used to offset increases in PM during any period of the year. Since the SO_X ERCs are being used to offset PM_{10} emissions, the above applies to the SO_X ERCs.

In addition, the overall offset ratio is equal to the multiplication of the distance and interpollutant ratios (1.5 x 1.000 = 1.5).

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
Remaining PM_{10} Emissions to be offset: (at a 1.5:1 ratio):	49,550	49,549	45,349	49,550
Remaining PM_{10} emissions to be offset with SO_X ERCs (at a 1.5:1 distance ratio and a 1.000:1 interpollutant SO_X:PM_{10} ratio):	49,550	49,549	45,349	49,550
Remaining ERCs from certificates N-762-5, S-2788-5, S-2789-5, and S-2790-5:	33,873	21,512	21,015	29,513
Remaining ERCs from certificates N-762-5, S-2788-5, S-2789-5, and S-2790-5:	0	0	0	0
Remaining PM_{10} emissions to be offset (at a 1.5:1 ratio and a 1.000:1 interpollutant SO_X:PM_{10} ratio):	15,677	28,037	24,334	20,037

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
Remaining PM10 Emissions to be offset: (at a 1.5:1 distance ratio and a 1.000:1 interpollutant SO_X:PM_{10} ratio):	15,677	28,037	24,334	20,037
Remaining ERCs from certificate S-2791-5:	92,179	23,666	69,157	96,288
1st qtr. ERCs applied to 2nd qtr. ERCs:	-4,371	4,371	0	0
Adjusted Remaining ERCs from certificate S-2791-5:	87,808	28,037	69,157	96,288
Remaining PM10 emissions to be offset (at a 1.5:1 ratio and a 1.000:1 interpollutant SO_X:PM_{10} ratio):	15,677	28,037	24,334	20,037
ERCs applied from certificate S-2791-5 partially withdrawn:	15,677	28,037	24,334	20,037
Remaining ERCs from certificate S-2791-5:	72,131	0	44,823	76,251

As seen above, the facility has sufficient credits to fully offset the quarterly SO_X and PM_{10} emissions increases associated with this project.

Offset Conditions:

The following conditions will ensure compliance with the offset requirements of this rule:

- Prior to initial operation of C-3953-10-0, C-3953-11-0, and C-3953-12-0, permittee shall provide NOx (as NO2) emission reduction credits for the following quantities of emissions: 1st quarter – 67,103 lb; 2nd quarter – 67,104 lb; 3rd quarter – 67,104 lb; and 4th quarter – 67,104 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. [District Rule 2201]

- Prior to initial operation of C-3953-10-0, C-3953-11-0, and C-3953-12-0, permittee shall provide VOC emission reduction credits for the following quantities of emissions: 1st quarter – 12,294 lb; 2nd quarter – 12,295 lb; 3rd quarter – 12,295 lb; and 4th quarter – 12,295 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. [District Rule 2201]

- Prior to initial operation of C-3953-10-0, C-3953-11-0, and C-3953-12-0, permittee shall provide PM_{10} emission reduction credits for the following quantities of emissions: 1st quarter – 33,087 lb; 2nd quarter – 33,086 lb; 3rd quarter – 33,086 lb; and 4th quarter – 33,086 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. SOx ERC's may be used to offset PM10 increases at an interpollutant ratio of 1.0 lb-SOx : 1.0 lb-PM10. [District Rule 2201]

- ERC certificate numbers (or any splits from these certificates) C-897-1, C-898-1, N-724-1, N-725-1, S-2812-1, S-2813-1, S-2817-1, C-899-2, C-902-2, N-720-2, N-722-2, N-726-2, N-728-2, S-2814-2, S-2321-2, C-896-4, N-721-4, N-723-4, S-2791-5, S-2790-5, S-2789-5, S-2788-5, or N-762-5 shall be used to supply the required offsets, unless a revised offsetting proposal is received and approved by the District, upon which this determination of compliance (DOC) shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of the DOC. [District Rule 2201]

D. Public Notification:

1. Applicability

District Rule 2201, section 5.4, requires a public notification for the affected pollutants from the following types of projects:

- New Major Sources
- Major Modifications
- New emission units with a PE > 100 lb/day of any one pollutant (IPE Notifications)
- Any project which results in the offset thresholds being surpassed (Offset Threshold Notification), and/or
- Any permitting action with a SSIPE exceeding 20,000 lb/yr for any one pollutant. (SSIPE Notice)

a. New Major Source Notice Determination

New Major Sources are new facilities, which are also Major Sources.

As shown in Section VII.C.6 above, the SSPE2 is greater than the Major Source threshold for NO_X, CO, VOC, and PM_{10}. Therefore, public noticing is required for this project for new Major Source purposes because this facility is becoming a new Major Source.

b. Major Modification

As demonstrated in Section VII.C.7 above, this project does not constitute a Major Modification; therefore, public noticing for Major Modification purposes is not required.

c. PE Notification

Applications which include a new emissions unit with a Potential to Emit greater than 100 pounds during any one day for any pollutant will trigger public noticing requirements. The potential to emit for each unit is summarized in the table below.

Post-Project Potential to Emit						
Permit Unit	NO_X (lb/day)	CO (lb/day)	VOC (lb/day)	PM_{10} (lb/day)	SO_X (lb/day)	NH_3 (lb/day)
C-3953-10-0	789.6	5,590.8	202.0	282.7	159.6	771.1
C-3953-11-0	789.6	5,590.8	202.0	282.7	159.6	771.1
C-3953-12-0	4.9	16.6	1.9	2.2	1.3	0
C-3953-13-0	51.8	6.8	5.8	0.9	0.1	0
C-3953-14-0	45.5	27.3	15.0	1.5	0.4	0
Threshold (lb/day)	**100**	**100**	**100**	**100**	**100**	**100**
Notification Required?	Yes	Yes	Yes	Yes	Yes	Yes

According to the table above, permit units C-3953-10-0 and -11-0 will each have a Potential to Emit greater than 100 lb/day for NO_X, CO, VOC, PM_{10}, SO_X, or NH_3 emissions. Therefore, public noticing will be required for PE > 100 lbs/day purposes.

e. Offset Threshold

Public notification is required if the Pre-Project Stationary Source Potential to Emit (SSPE1) is increased from a level below the offset threshold to a level exceeding the emissions offset threshold, for any pollutant.

The following table compares the SSPE1 with the SSPE2 in order to determine if any offset thresholds have been surpassed with this project.

Offset Threshold				
Pollutant	SSPE1 (lb/year)	SSPE2 (lb/year)	Offset Threshold	Public Notice Required?
NO_X	0	288,618	20,000 lb/year	Yes
CO	0	1,205,418	200,000 lb/year	Yes
VOC	0	69,222	20,000 lb/year	Yes
PM_{10}	0	161,550	29,200 lb/year	Yes
SO_X	0	33,521	54,750 lb/year	No

As detailed above, offset thresholds were surpassed for NO_X, CO, VOC, and PM_{10} emissions with this project; therefore public noticing is required for offset purposes.

f. SSIPE Notification

Public notification is required for any permitting action that results in a Stationary Source Increase in Permitted Emissions (SSIPE) of more than 20,000 lb/year of any affected pollutant. According to District policy, the SSIPE is calculated as the Post Project Stationary Source Potential to Emit (SSPE2) minus the Pre-Project Stationary Source Potential to Emit (SSPE1), i.e. SSIPE = SSPE2 – SSPE1. The values for SSPE2 and SSPE1 are calculated according to Rule 2201, Sections 4.9 and 4.10, respectively. The SSIPE is compared to the SSIPE Public Notice thresholds in the following table:

SSIPE Notification					
Pollutant	**SSPE2 (lb/year)**	**SSPE1 (lb/year)**	**SSIPE (lb/year)**	**SSIPE Public Notice Threshold**	**Public Notice Required?**
NO_X	288,618	0	288,618	20,000 lb/year	Yes
CO	1,205,418	0	1,205,418	20,000 lb/year	Yes
VOC	69,222	0	69,222	20,000 lb/year	Yes
PM_{10}	161,550	0	161,550	20,000 lb/year	Yes
SO_X	33,521	0	33,521	20,000 lb/year	Yes

As demonstrated above, the SSIPE's for NO_X, CO, VOC, PM_{10} and SO_X emissions were greater than 20,000 lb/year; therefore public noticing for SSIPE purposes is required.

2. Public Notice Requirements

Section 5.5 details the actions taken by the District when pubic noticing is triggered according to the application types above. Since public noticing requirements are triggered for this project (i.e. New Major Source, PE's > 100 lbs/day, offset thresholds being exceeded, and SSIPEs greater than 20,000 lbs/year), the District shall public notice this project according to the requirements of Section 5.5.

E. Daily Emission Limits:

Daily emissions limitations (DELs) and other enforceable conditions are required by Section 3.15 to restrict a unit's maximum daily emissions, to a level at or below the emissions associated with the maximum design capacity. Per Sections 3.15.1 and 3.15.2, the DEL must be contained in the latest ATC and contained in or enforced by the latest PTO and enforceable, in a practicable manner, on a daily basis.

Proposed Rule 2201 (DEL) Conditions:

i. C-3953-10-0 and C-3953-11-0 (Turbines)

For the turbines, the DELs for NO_X, CO, VOC, PM_{10}, SO_X, and NH_3 will consist of lb/day and/or emission factors.

- Emission rates from this unit (with duct burner firing), except during startup and shutdown periods, shall not exceed any of the following limits: NOx (as NO2) – 17.20 lb/hr and 2.0 ppmvd @ 15% O2; VOC (as methane) – 5.89 lb/hr and 2.0 ppmvd @ 15% O2; CO – 10.60 lb/hr and 2.0 ppmvd @ 15% O2; PM10 – 11.78 lb/hr; or SOx (as SO2) – 6.65 lb/hr. NOx (as NO2) emission limits are one hour rolling averages. All other emission limits are three hour rolling averages. [District Rules 2201, 4001, and 4703]

- Emission rates from this unit (without duct burner firing), except during startup and shutdown periods, shall not exceed any of the following limits: NOx (as NO2) - 13.55 lb/hr and 2.0 ppmvd @ 15% O2; VOC (as methane) - 3.34 lb/hr and 1.4 ppmvd @ 15% O2; CO – 8.35 lb/hr and 2.0 ppmvd @ 15% O2; PM10 – 8.91 lb/hr; or SOx (as SO2) – 5.23 lb/hr. NOx (as NO2) emission limits are one hour rolling averages. All other emission limits are three hour rolling averages. [District Rules 2201, 4001, and 4703]

- During start-up and shutdown, CTG exhaust emission rates shall not exceed any of the following limits: NO_X (as NO_2) – 160 lb/hr; CO – 1,000 lb/hr; VOC (as methane) – 16 lb/hr; PM_{10} – 11.78 lb/hr; SO_X (as SO_2) – 6.652 lb/hr; or NH_3 – 32.13 lb/hr. [District Rules 2201 and 4703]

- Daily emissions from the CTG shall not exceed the following limits: NO_X (as NO_2) – 412.8 lb/day; CO – 254.4 lb/day; VOC – 141.4 lb/day; PM_{10} – 282.7 lb/day; SO_X (as SO_2) – 159.6 lb/day, or NH_3 – 771.1 lb/day. [District Rule 2201]

- Emissions from this unit, on days when a startup and/or shutdown occurs, shall not exceed the following limits: NOx (as NO2) – 789.6 lb/day; VOC – 202.0 lb/day; CO – 5,590.8 lb/day; PM10 – 282.7 lb/day; SOx (as SO2) – 159.6 lb/day, or NH_3 – 771.1 lb/day. [District Rule 2201]

- The ammonia (NH3) emissions shall not exceed 10 ppmvd @ 15% O2 over a 24 hour rolling average. [District Rule 2201]

- The CTG shall be fired exclusively on PUC-regulated natural gas with a sulfur content no greater than 1.0 grain of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201 and 40 CFR 60.4330(a)(2)]

- Annual average of the sulfur content of the CTG shall not exceed 0.36 grain of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201]

In addition to the daily emissions limits specified above, the following conditions will also be included to ensure continued compliance for the proposed turbines:

- Annual emissions from the CTG, calculated on a twelve month rolling basis, shall not exceed any of the following limits: NO_X (as NO_2) – 143,951 lb/year; CO – 601,810 lb/year; VOC – 34,489 lb/year; PM_{10} – 80,656 lb/year; or SO_X (as SO_2) – 16,694 lb/year; or NH_3 – 208,708 lb/year. [District Rule 2201]

- Each one hour period shall commence on the hour. Each one hour period in a three hour rolling average will commence on the hour. The three hour average will be compiled from the three most recent one hour periods. Each one hour period in a twenty-four hour average for ammonia slip will commence on the hour. [District Rule 2201]

- Daily emissions will be compiled for a twenty-four hour period starting and ending at twelve-midnight. Each month in the twelve consecutive month rolling average emissions shall commence at the beginning of the first day of the month. The twelve consecutive month rolling average emissions to determine compliance with annual emissions limitations shall be compiled from the twelve most recent calendar months. [District Rule 2201]

ii. C-3953-12-0 (Boiler)

The DELs for the boiler will consist of lb/MMBtu and ppmv emissions limits. This will be sufficient to establish a maximum daily potential to emit based on the maximum daily fuel use limit.

- Emission rates from this unit shall not exceed any of the following limits: NOx (as NO2) - 9.0 ppmvd @ 3% O2 or 0.011 lb/MMBtu; VOC (as methane) - 10.0 ppmvd @ 3% O2; CO - 50.0 ppmvd @ 3% O2 or 0.037 lb/MMBtu; PM10 - 0.005 lb/MMBtu; or SOx (as SO2) - 0.00282 lb/MMBtu. [District Rules 2201, 4305, 4306, and 4351]

In addition the following permit conditions will appear on the permit:

- {2964} The unit shall only be fired on PUC-regulated natural gas. [District Rule 2201]

iii. C-3953-13-0 (Diesel IC engine fire pump)

For the emergency IC engine powering a fire pump, the DELs will be stated in the form of emission factors, the maximum engine horsepower rating, and the maximum operational time of 24 hours per day.

- Emissions from this IC engine shall not exceed any of the following limits: 3.4 g-NOx/bhp-hr, 0.447 g-CO/bhp-hr, or 0.38 g-VOC/bhp-hr. [District Rule 2201 and 13 CCR 2423 and 17 CCR 93115]

- Emissions from this IC engine shall not exceed 0.059 g-PM10/bhp-hr based on USEPA certification using ISO 8178 test procedure. [District Rules 2201 and 4102 and 13 CCR 2423 and 17 CCR 93115]

- {3395} Only CARB certified diesel fuel containing not more than 0.0015% sulfur by weight is to be used. [District Rules 2201 and 4801 and 17 CCR 93115]

iv. C-3953-14-0 (Natural gas IC engine electrical generator)

For the emergency IC engine powering a generator, the DELs will be stated in the form of emission factors, the maximum engine horsepower rating, and the maximum operational time of 24 hours per day.

- Emissions from this IC engine shall not exceed any of the following limits: 1.0 g-NOx/bhp-hr, 0.034 g-PM10/bhp-hr, 0.6 g-CO/bhp-hr, or 0.33 g-VOC/bhp-hr. [District Rule 2201]

- {3491} This IC engine shall be fired on Public Utility Commission (PUC) regulated natural gas only. [District Rules 2201 and 4801]

F. Compliance Certification:

Section 4.15.2 of this Rule requires the owner of a new major source or a source undergoing a major modification to demonstrate to the satisfaction of the District that all other major sources owned by such person and operating in California are in compliance with all applicable emission limitations and standards. As discussed above, this facility is a new major source; therefore this requirement is applicable. Included in Attachment I is Avenal Power Center's certification for the Avenal Energy Project.

G. Air Quality Impact Analysis:

Section 4.14.2 of this Rule requires that an air quality impact analysis (AQIA) be conducted for the purpose of determining whether the operation of the proposed equipment will cause or make worse a violation of an air quality standard. The Technical Services Division of the SJVAPCD conducted the required analysis. Refer to Attachment G of this document for the AQIA summary sheet.

The AQIA performed for this project was analyzed based on the facility's preliminary proposal. The facility originally proposed CO emissions from the two CTG's to be limited to 4.0 ppmvd @ 15% O_2. However, due to comments made during the public notice period, the facility limited their CO emissions to 2.0 ppmvd @ 15% O_2. Since the new proposed emission factor is lower than the original emission factor and will not result in an increase in air pollutants, a new AQID will not be required to be performed for this project.

The proposed location is in an attainment area for NO_X, CO, and SO_X. As shown by the table below, the proposed equipment will not cause a violation of an air quality standard for NO_X, CO, or SO_X.

AAQA Results Summary					
Pollutant	1 hr Average	3 hr Average	8 hr Average	24 hr Average	Annual Average
CO	Pass	N/A	Pass	N/A	N/A
NO_x	Pass	N/A	N/A	N/A	Pass
SO_x	Pass	Pass	N/A	Pass	Pass

The proposed location is in a non-attainment area for PM_{10}. The increase in the ambient PM_{10} concentration due to the proposed equipment is shown on the table titled Calculated Contribution. The levels of significance, from 40 CFR Part 51.165 (b)(2), are shown on the table titled Significance Levels.

Significance Levels					
Pollutant	Significance Levels ($\mu g/m^3$) - 40 CFR Part 51.165 (b)(2)				
	Annual Avg.	24 hr Avg.	8 hr Avg.	3 hr Avg.	1 hr Avg.
PM_{10}	1.0	5	N/A	N/A	N/A

Calculated Contribution					
Pollutant	Calculated Contributions ($\mu g/m^3$)				
	Annual Avg.	24 hr Avg.	8 hr Avg.	3 hr Avg.	1 hr Avg.
PM_{10}	0.38	1.6	N/A	N/A	N/A

As shown, the calculated contribution of PM_{10} will not exceed the EPA significance level. This project is not expected to cause or make worse a violation of an air quality standard.

H. Compliance Assurance:

1. Source Testing

i. C-3953-10-0 and C-3953-11-0

District Rule 4703 requires NO_X and CO emission testing as well as percent turbine efficiency testing on an annual basis. The District Source Test Policy (APR 1705 10/09/97) requires annual testing for all pollutants controlled by catalysts. The control equipment will include a SCR system and an oxidation catalyst. Ammonia slip is an indicator of how well the SCR system is performing and PM_{10} emissions are a good indicator of how well the inlet air cooler/filter are performing.

Therefore, source testing for NO_X, CO, VOC, PM_{10}, and ammonia slip will be required within 60 days after the end of the commissioning period and at least once every 12 months thereafter.

Also, initial source testing of NO_X, CO, and VOC startup emissions will be required for one gas turbine engine initially and not less than every seven years thereafter. This testing will serve two purposes: to validate the startup emission estimates used in the emission calculations and to verify that the CEMs accurately measure startup emissions.

Each CTG will have a separate exhaust stack. The units will be equipped with CEMs for NO_X, CO, and O_2. Each CTG will be equipped with an individual CEM. Each CEM will have two ranges to allow accurate measurements of NO_X and CO emissions during startup. The CEMs must meet the installation, performance, relative accuracy, and quality assurance requirements specified in 40 CFR 60.13 and Appendix B (referenced in the CEM requirements of Rule 4703) and the acid rain requirements in 40 CFR Part 75.

40 CFR Part 60 subpart KKKK requires that fuel sulfur content be documented or monitored. Refer to the monitoring section of this document for a discussion of the fuel sulfur testing requirements.

40 CFR Part 60 subpart Db requires NO_X testing for the duct burners. The District will accept the NO_X source testing required by District Rule 4703 as equivalent to NO_X testing required by 40 CFR 60 subpart Db.

ii. C-3953-12-0

This unit is subject to District Rule 4305, _Boilers, Steam Generators and Process Heaters, Phase 2_, and District Rule 4306, _Boilers, Steam Generators and Process Heaters, Phase 3_. Source testing requirements, in accordance with District Rules 4305 and 4306, will be discussed in Section VIII, _District Rules 4305 and 4306_, of this evaluation.

iii. C-3953-13-0 and C-3953-14-0

Pursuant to District Policy APR 1705, source testing is not required for emergency standby IC engines to demonstrate compliance with Rule 2201.

2. Monitoring

i. C-3953-10-0 and C-3953-11-0

Monitoring of NO_X emissions is required by District Rule 4703. The applicant has proposed a CEMS for NO_X.

CO monitoring is not specifically required by any applicable Rule or Regulation. Nevertheless, due to erratic CO emission concentrations during start-up and shutdown periods, it is necessary to limit the CO emissions on a pound per hour basis. Therefore, a CO CEMS is necessary to show compliance with the CO limits of this permit. The applicant has proposed a CO CEMS.

40 CFR Part 60 Subpart KKKK and District Rule 4703 requires monitoring of the fuel consumption. Fuel consumption monitoring will be required.

40 CFR Part 60 Subpart KKKK requires monitoring of the fuel sulfur content. The gas supplier, Pacific Gas & Electric (PG&E), may deliver gas with a sulfur content of up to 1.0 gr/scf. Since the sulfur content of the natural gas would not exceed this value, it is District practice to allow the facility to demonstrate compliance with the limit by providing gas purchase contracts, supplier certification, tariff sheet or transportation contract; or, if these documents cannot be provided, physically monitor the fuel sulfur content weekly for eight consecutive weeks and semi-annually thereafter if the fuel sulfur content remains below 1.0 gr/scf. Avenal Power Center, LLC will be operating these turbines in compliance with the fuel sulfur content monitoring requirements as described in the Rule 4001, Subpart KKKK discussion below. Therefore, compliance with the monitoring requirements will be satisfied.

ii. C-3953-12-0

As required by District Rule 4305, *Boilers, Steam Generators and Process Heaters, Phase 2*, and District Rule 4306, *Boilers, Steam Generators and Process Heaters, Phase 3*, this unit is subject to monitoring requirements. Monitoring requirements, in accordance with District Rules 4305 and 4306, will be discussed in Section VIII, *District Rules 4305 and 4306*, of this evaluation.

iii. C-3953-13-0 and C-3953-14-0

No monitoring is required to demonstrate compliance with Rule 2201.

3. Recordkeeping

i. C-3953-10-0 and C-3953-11-0

The applicant will be required to keep records of all of the parameters that are required to be monitored. Refer to section VIII.F.2 of this document for a discussion of the parameters that will be monitored.

ii. C-3953-12-0

As required by District Rule 4305, *Boilers, Steam Generators and Process Heaters, Phase 2*, and District Rule 4306, *Boilers, Steam Generators and Process Heaters, Phase 3*, this unit is subject to recordkeeping requirements. Recordkeeping requirements, in accordance with District Rules 4305 and 4306, will be discussed in Section VIII, *District Rules 4305 and 4306*, of this evaluation.

The following permit condition will be listed on permit as follows:

- All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rules 1070, 4305, and 4306]

iii. C-3953-13-0 and C-3953-14-0

Recordkeeping is required to demonstrate compliance with the offset, public notification, and daily emission limit requirements of Rule 2201. As required by District Rule 4702, *Stationary Internal Combustion Engines - Phase 2*, these IC engines are subject to recordkeeping requirements. Recordkeeping requirements, in accordance with District Rule 4702, will be discussed in Section VIII, *District Rule 4702*, of this evaluation.

4. Reporting

i. C-3953-10-0 and C-3953-11-0

40 CFR Part 60 Subpart KKKK requires that the facility report the use of fuel with a sulfur content of more than 0.8% by weight. Such reporting will be required.

40 CFR Part 60 Subpart KKKK requires the reporting of exceedences of the NO_X emission limit of the permit. Such reporting will be required.

ii. C-3953-12-0

No reporting is required to demonstrate compliance with Rule 2201.

iii. C-3953-13-0 and C-3953-14-0

No reporting is required to demonstrate compliance with Rule 2201.

Rule 2520 Federally Mandated Operating Permits

This project will be subject to Rule 2520 (Title V) because it will meet the following criteria specified in section 2.0:

- Section 2.3 states, "Any major source." The facility will be a major source for NO_X, CO, VOC, and PM_{10} after this project.
- Section 2.4 states, "Any emissions unit, including an area source, subject to a standard or other requirement promulgated pursuant to section 111 (NSPS) or 112 (HAPs) of the CAA..." The turbines are subject to NSPS.
- Section 2.5 states "A source with an acid rain unit for which application for an acid rain permit is required pursuant to Title IV (Acid Rain Program) of the CAA." The turbines are subject to the acid rain program.
- Section 2.6 states, "Any source required to have a preconstruction review permit pursuant to the requirements of the prevention of significant deterioration (PSD) program under Title I of the Federal Clean Air Act." This facility is required to obtain a PSD permit from the EPA.

Pursuant to Rule 2520 section 5.3.1 Avenal Power Center must submit a Title V application within 12 months of commencing operations. No action is required at this time.

- Permittee shall submit an application to comply with SJVUAPCD District Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520]

Rule 2540 Acid Rain Program

The proposed CTG's are subject to the acid rain program as phase II units, i.e. they will be installed after 11/15/90 and each has a generator nameplate rating greater than 25 MW.

The acid rain program will be implemented through a Title V operating permit. Federal regulations require submission of an acid rain permit application at least 24 months before the later of 1/1/2000 or the date the unit expects to generate electricity. The facility anticipates beginning commercial operation in November of 2011.

The acid rain program requirements for this facility are relatively minimal. Monitoring of the NO_X and SO_X emissions and a relatively small quantity of SO_X allowances (from a national SO_X allowance bank) will be required as well as the use of a NO_X CEM.

The following condition will be placed on permits C-3953-10-0, -11-0 and -14-0 to ensure that Avenal Power Center, LLC submits an application to comply with the requirements of the acid rain program within the appropriate timeframe:

- Permittee shall submit an application to comply with SJVUAPCD District Rule 2540 - Acid Rain Program. [District Rule 2540]

Rule 2550 Federally Mandated Preconstruction Review for Major Sources of Air Toxics

Section 2.0 states, "*The provisions of this rule shall only apply to applications to construct or reconstruct a major air toxics source with Authority to Construct issued on or after June 28, 1998.*" The applicant has provided the following analysis for Noncriteria pollutants/HAPs.

Noncriteria pollutants are compounds that have been identified as pollutants that pose a significant health hazard. Nine of these pollutants are regulated under the Federal New Source Review program: lead, asbestos, beryllium, mercury, fluorides, sulfuric acid mist, hydrogen sulfide, total reduced sulfur, and reduced sulfur compounds.[8]

In addition to these nine compounds, the federal Clean Air Act lists 189 substances as potential hazardous air pollutants (Clean Air Act Sec. 112(b)(1)). The SJVAPCD has also published a list of compounds it defines as potential toxic air contaminants (Toxics

[8] These pollutants are regulated under federal and state air quality programs; however, they are evaluated as noncriteria pollutants by the California Energy Commission (CEC).

Policy, May 1991; Rule 2-1-316). Any pollutant that may be emitted from the project and is on the federal New Source Review List, the federal Clean Air Act list, and/or the SJVAPCD toxic air contaminant list has been evaluated.

Noncriteria pollutant emission factors for the analysis of emissions from the gas turbines were obtained from AP-42 (Table 3.1-3, 4/00, and Table 3.4-1 of the Background Document for Section 3.1), from the California Air Resources Board's CATEF database for gas turbines, and from source tests on a similar turbine. Specifically, factors for all pollutants except formaldehyde, hexane, propylene, and naphthalene and other PAHs were taken from AP-42.[9] AP-42 did not contain factors for hexane or propylene, and did not include speciated data for PAHs. Factors for these pollutants and for naphthalene were taken from the CATEF database (mean values). The emission factor for formaldehyde was taken from the results of a June 2000 source test on a dry Low NO_X combustor-equipped large frame turbine.

Hazardous Air Pollutant Emissions (per CATEF)
Avenal Energy Project – GE Frame 7 (with Duct Burners)

Hazardous Air Pollutant	CATEF Emission Factor (lb/MMSCF)(1)	Maximum Hourly Emissions per Turbine (lb/hr) (2)	Maximum Annual Emissions per Turbine (tpy) (3)	Maximum Annual Emissions both Turbines (tpy)
Acetaldehyde	4.08E-02	0.09	0.33	0.67
Acrolein	3.69E-03	0.01	0.03	6.04E-02
Benzene	3.33E-03	0.01	0.03	5.45E-02
1,3-Butadiene	4.39E-04	9.38E-04	3.59E-03	7.19E-03
Ethyl benzene	3.26E-02	0.07	0.27	0.53
Formaldehyde	1.65E-01	0.35	1.35	2.70
Hexane	2.59E-01	0.55	2.12	4.24
Naphthalene	1.33E-03	2.84E-03	1.09E-02	2.18E-02
Polycyclic aromatic hydrocarbons (PAH)	---	---	---	---
Anthracene	3.38E-05	7.22E-05	2.77E-04	5.53E-04
Benzo(a)anthracene	2.26E-05	4.83E-05	1.85E-04	3.70E-04
Benzo(a)pyrene	1.39E-05	2.97E-05	1.14E-04	2.28E-04
Benzo(b)fluoranthrene	1.13E-05	2.41E-05	9.25E-05	1.85E-04
Benzo(k)fluoranthrene	1.10E-05	2.35E-05	9.00E-05	1.80E-04
Chrysene	2.52E-05	5.38E-05	2.06E-04	4.12E-04
Dibenz(a,h)anthracene	2.35E-05	5.02E-05	1.92E-04	3.85E-04
Indeno(1,2,3-cc)pyrene	2.35E-05	5.02E-05	1.92E-04	3.85E-04
Propylene oxide	2.96E-02	6.32E-02	2.42E-01	0.48
Toluene	1.33E-01	0.28	1.09	2.18
Xylenes	6.53E-02	0.14	0.53	1.07
Total			**6.01**	**12.02**

(1) From AP-42 and CATEF databases and source tests.
(2) Based on a maximum hourly turbine fuel use of 2,224.1 MMBtu/hr (with duct burner) and fuel HHV of 1,021 Btu/scf. (2.14 MMscf/hr)

[9] Factors for acrolein and benzene reflect the use of an oxidation catalyst and were taken from Table 3.4-1 of the Background Document for Section 3.1.

(3) Based on a maximum annual turbine fuel use of 16,711,728 MMBtu/year (with duct burner) and fuel HHV of 1,021 Btu/scf. (16,368 MMscf/yr)

Although the turbines/HRSGs will be equipped with oxidation catalyst systems, only the acrolein and benzene emission factors reflect any control effectiveness. As discussed above, these factors are based on test data rather than any assumption regarding catalyst control efficiency.

Therefore, as emissions of each individual HAP are below 10 tons per year and total HAP emissions are below 25 tons per year, the Avenal Power Center, LLC Project will not be a major air toxics source and the provisions of this rule do not apply.

Rule 4001 New Source Performance Standards

40 CFR 60 – Subpart Dc

NSPS Subpart Dc applies to steam generating units that are constructed, reconstructed, or modified after 6/9/89 and have a maximum design heat input capacity of 100 MMBtu/hr or less, but greater than or equal to 10 MMBtu/hr. Subpart Dc has standards for SO_X and PM_{10}.

60.42c – Standards for Sulfur Dioxide

Since coal is not combusted by the boiler in this project, the requirements of this section are not applicable.

60.43c – Standards for Particulate Matter

The boiler is not fired on coal, combusts mixtures of coal with other fuels, combusts wood, combusts mixtured of wood with other fuels, or oil; therefore it will not be subject to the requirements of this section.

60.44c – Compliance and Performance Tests Methods and Procedures for Sulfur Dioxide.

Since the boiler in this project is not subject to the sulfur dioxide requirements of this subpart, no testing to show compliance is required. Therefore, the requirements of this section are not applicable to the boiler in this project.

60.45c – Compliance and Performance Test Methods and Procedures for Particulate Matter

Since the boiler in this project is not subject to the particulae matter requirements of this subpart, no testing to show compliance is required. Therefore, the requirements of this section are not applicable to the boiler in this project.

60.46c – Emission Monitoring for Sulfur Dioxide

Since the boiler in this project is not subject to the sulfur dioxide requirements of this subpart, no monitoring is required. Therefore, the requirements of this section are not applicable to the boiler in this project.

60.47c – Emission Monitoring for Particulate Matter

Since the boiler in this project is not subject to the particulate matter requirements of this subpart, no monitoring is required. Therefore, the requirements of this section are not applicable to the boiler in this project.

60.48c – Reporting and Recordingkeeping Requirements

Section 60.48c (a) states that the owner or operator of each affected facility shall submit notification of the date of construction or reconstruction, anticipated startup, and actual startup, as provided by §60.7 of this part. This notification shall include:

(1) The design heat input capacity of the affected facility and identification of fuels to be combusted in the affected facility.

The design heat input capacity and type of fuel combusted at the facility will be listed on the unit's equipment description. No conditions are required to show compliance with this requirement.

(2) If applicable, a copy of any Federally enforceable requirement that limits the annual capacity factor for any fuel mixture of fuels under §60.42c or §40.43c.

This requirement is not applicable since the units are not subject to §60.42c or §40.43c.

(3) The annual capacity factor at which the owner or operator anticipates operating the affected facility based on all fuels fired and based on each individual fuel fired.

The facility has not proposed an annual capacity factor; therefore one will not be required.

(4) Notification if an emerging technology will be used for controlling SO_2 emissions. The Administrator will examine the description of the control device and will determine whether the technology qualifies as an emerging technology. In making this determination, the Administrator may require the owner or operator of the affected facility to submit additional information concerning the control device. The affected facility is subject to the provisions of §60.42c(a) or (b)(1), unless and until this determination is made by the Administrator

This requirement is not applicable since the units will not be equipped with an emerging technology used to control SO_2 emissions.

Section 60.48 c (g) states that the owner or operator of each affected facility shall record and maintain records of the amounts of each fuel combusted during each day. The following conditions will be added to the permit to assure compliance with this section.

- A non-resettable, totalizing mass or volumetric fuel flow meter to measure the amount of fuel combusted in the unit shall be installed, utilized and maintained. [District Rules 2201 and 40 CFR 60.48 (c)(g)]

- Permittee shall maintain daily records of the type and quantity of fuel combusted by the boiler. [District Rules 2201 and 40 CFR 60.48 (c)(g)]

Section 60.48 c (i) states that all records required under this section shall be maintained by the owner or operator of the affected facility for a period of two years following the date of such record. District Rule 4306 requires that records be kept for five years.

<u>40 CFR 60 – Subpart GG</u>

40 CFR Part 60 Subpart GG applies to all stationary gas turbines with a heat input greater than 10.7 gigajoules per hour (10.2 MMBtu/hr), that commence construction, modification, or reconstruction after October 3, 1977. Avenal Power Center, LLC has indicated that the installation and construction of the proposed turbines will be completed in 2011. Therefore, these turbines meet the applicability requirements of this subpart.

40 CFR 60 Subpart KKKK, Section 60.4305(a), states that this subpart applies to all stationary gas turbines with a heat input greater than 10.7 gigajoules (10 MMBtu) per hour, which commenced construction, modification, or reconstruction after February 18, 2005. Avenal Power Center, LLC has indicated that the installation and construction of the proposed turbines will be completed in 2011. Therefore, these turbines also meet the applicability requirements of this subpart.

40 CFR 60 Subpart KKKK, Section 60.4305(b), states that stationary combustion turbines regulated under this subpart are exempt from the requirements of 40 CFR 60 Subpart GG. As discussed above, 40 CFR 60 Subpart KKKK is applicable to these proposed turbines. Therefore, they are exempt from the requirements of 40 CFR 60 Subpart GG and no further discussion is required.

40 CFR 60 - Subpart IIII

§60.4200 - Applicability

40 CFR Part 60 Subpart IIII applies to all owners and operators of stationary compression ignited internal combustion engines that commence construction after July 11, 2005, where the engines are:

1) Manufactured after April 1, 2006, if not a fire pump engine.
2) Manufactured as a National Fire Protection Association (NFPA) fire pump engine after July 1, 2006.

Since the proposed engines will be installed after July 11, 2005 and will be manufactured after April 1, 2006, this subpart applies.

All of the applicable stands of this subpart are less restrictive than current District requirements. This engine will comply with all current District standards so further discussion is required.

40 CFR 60 – Subpart KKKK

40 CFR Part 60 Subpart KKKK applies to all stationary gas turbines rated at greater than or equal to 10 MMBtu/hr that commence construction, modification, or reconstruction after February 18, 2005. The proposed gas turbines involved in this project have a rating of 1,794.5 MMBtu/hr and will be installed after February 18, 2005. Therefore, this subpart applies to these gas turbines.

Subpart KKKK established requirements for nitrogen oxide (NO_X) and sulfur dioxide (SO_X) emissions.

Section 60.4320 - Standards for Nitrogen Oxides:

Paragraph (a) states that NO_X emissions shall not exceed the emission limits specified in Table 1 of this subpart. Paragraph (b) states that if you have two or more turbines that are connected to a single generator, each turbine must meet the emission limits for NO_X. Table 1 states that new, modified, or reconstructed turbines firing natural gas with a combustion turbine heat input at peak load of greater than 850 MMBtu/hr shall meet a NO_X emissions limit of 15 ppmvd @ 15% O_2 or 54 ng/J of useful output (0.43 lb/MWh).

Avenal Power Center is proposing a NO_X emission concentration limit of 2.0 ppmvd @ 15% O_2 for each turbine. Therefore, the proposed turbines will be operating in compliance with the NO_X emission requirements of this subpart. The following conditions will ensure continued compliance with the requirements of this section:

- Emission rates from this unit (with duct burner firing), except during startup and shutdown periods, shall not exceed any of the following limits: NOx (as NO2) – 17.44 lb/hr and 2.0 ppmvd @ 15% O2; VOC (as methane) – 6.13 lb/hr and 2.0 ppmvd @ 15% O2; CO – 10.60 lb/hr and 2.0 ppmvd @ 15% O2; PM10 – 11.78 lb/hr; or SOx (as SO2) – 6.72 lb/hr. NOx (as NO2) emission limits are one hour rolling averages. All other emission limits are three hour rolling averages. [District Rules 2201, 4001, and 4703]

- Emission rates from this unit (without duct burner firing), except during startup and shutdown periods, shall not exceed any of the following limits: NOx (as NO2) - 13.28 lb/hr and 2.0 ppmvd @ 15% O2; VOC (as methane) - 3.23 lb/hr and 1.4 ppmvd @ 15% O2; CO – 8.35 lb/hr and 2.0 ppmvd @ 15% O2; PM10 – 8.97 lb/hr; or SOx (as SO2) – 5.11 lb/hr. NOx (as NO2) emission limits are one hour rolling averages. All other emission limits are three hour rolling averages. [District Rules 2201, 4001, and 4703]

<u>Section 60.4330 - Standards for Sulfur Dioxide:</u>

Paragraph (a) states that if your turbine is located in a continental area, you must comply with one of the following:

(1) Operator must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO_2 in excess of 110 nanograms per Joule (ng/J) (0.90) pounds per megawatt-hour (lb/MWh)) gross output; or
(2) Operator must not burn in the subject stationary combustion turbine any fuel which contains total potential sulfur emissions in excess of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input.

Avenal Power Center is proposing to burn natural gas fuel in each of these turbines with a maximum sulfur content of 1.0 grain/ 100 scf (0.00285 lb/MMBtu). Therefore, the proposed turbines will be operating in compliance with the SO_X emission requirements of this section. The following condition will ensure continued compliance with the requirements of this section:

- The CTG shall be fired exclusively on PUC-regulated natural gas with a sulfur content of no greater than 1.0 grains of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201 and 40 CFR 60.4330(a)(2)]

<u>Section 60.4335 – NO_X Compliance Demonstration, with Water or Steam Injection:</u>

Paragraph (a) states that when a turbine is using water or steam injection to reduce NO_X emissions, you must install, calibrate, maintain and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine when burning a fuel that requires water or steam injection for compliance.

Avenal Power Center does not use water or steam injection in their turbines therefore; the requirements of this section are not applicable to the turbines in this project.

Section 60.4340 – NO_X Compliance Demonstration, without Water or Steam Injection:

Paragraph (b) states that as an alternative to annual source testing, the facility may install, calibrate, maintain and operate one of the following continuous monitoring systems:

(1) Continuous emission monitoring as described in §§60.4335(b) and 60.4345, or
(2) Continuous parameter monitoring

Avenal Power Center has proposed to install a CEMS system as described in §§60.4335(b) and 60.4345 therefore; the following condition will ensure continued compliance with the requirements of this section:

- The owner or operator shall install, certify, maintain, operate and quality-assure a Continuous Emission Monitoring System (CEMS) which continuously measures and records the exhaust gas NO_X, CO and O_2 concentrations. Continuous emissions monitor(s) shall be capable of monitoring emissions during normal operating conditions, and during startups and shutdowns~~,~~ provided the CEMS passes the relative accuracy requirement for startups and shutdowns specified herein. If relative accuracy of CEMS cannot be demonstrated during startup conditions, CEMS results during startup and shutdown events shall be replaced with startup emission rates obtained from source testing to determine compliance with emission limits contained in this document. [District Rules 1080 and 4703 and 40 CFR 60.4340(b)(1)]

Section 60.4345 – CEMS Equipment Requirements:

Paragraph (a) states that each NO_X diluent CEMS must be installed and certified according to Performance Specification 2 (PS 2) in Appendix B to this part, except the 7-day calibration drift is based on unit operating days, not calendar days. With state approval, Procedure 1 in Appendix F to this part is not required. Alternatively, a NO_X diluent CEMS that is installed and certified according to Appendix A of Part 75 of this chapter is acceptable for use under this subpart. The relative accuracy test audit (RATA) of the CEMS shall be performed on a lb/MMBtu basis.

Paragraph (b) states that as specified in §60.13(e)(2), during each full unit operating hour, both the NO_X monitor and the diluent monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one valid data point must be obtained with each monitor for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required for each monitor to validate the NO_X emission rate for the hour.

Paragraph (c) states that each fuel flowmeter shall be installed, calibrated, maintained, and operated according to the manufacturer's instructions. Alternatively, with state approval, fuel flowmeters that meet the installation, certification, and quality assurance requirements of Appendix D to Part 75 of this chapter are acceptable for use under this subpart.

Paragraph (d) states that each watt meter, steam flow meter, and each pressure or temperature measurement device shall be installed, calibrated, maintained, and operated according to manufacturer's instructions.

Paragraph (e) states that the owner or operator shall develop and keep on-site a quality assurance (QA) plan for all of the continuous monitoring equipment described in paragraphs (a), (c), and (d) of this section. For the CEMS and fuel flow meters, the owner or operator may, with state approval, satisfy the requirements of this paragraph by implementing the QA program and plan described in section 1 of Appendix B to Part 75 of this chapter.

Avenal Power Center will be required to install and operate a NO_X CEMS in accordance with the requirements of this section. As discussed above, Avenal Power Center is not required to install a fuel flow meter, watt meter, steam flow meter, or a pressure or temperature measurement device to comply with the requirements of this subpart. Therefore, the proposed turbines will be operating in compliance with the requirements of this section. The following conditions will ensure continued compliance with the requirements of this section:

- The NO_X, CO and O_2 CEMS shall meet the requirements in 40 CFR 60, Appendix F Procedure 1 and Part 60, Appendix B Performance Specification 2 (PS 2), or shall meet equivalent specifications established by mutual agreement of the District, the ARB, and the EPA. [District Rule 1080 and 40 CFR 60.4345(a)]

- The CEMS shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period or shall meet equivalent specifications established by mutual agreement of the District, the ARB and the EPA. [District Rule 1080 and 40 CFR 60.4345(b)]

<u>Section 60.4350 – CEMS Data and Excess NO_X Emissions:</u>

Section 60.4350 states that for purposes of identifying excess emissions:

(a) All CEMS data must be reduced to hourly averages as specified in §60.13(h).

(b) For each unit operating hour in which a valid hourly average, as described in §60.4345(b), is obtained for both NO_X and diluent monitors, the data acquisition and handling system must calculate and record the hourly NO_X emission rate in units of ppm or lb/MMBtu, using the appropriate equation from Method 19 in Appendix A of this part. For any hour in which the hourly average O_2 concentration exceeds 19.0 percent O_2 (or the hourly average CO_2 concentration is less than 1.0 percent CO_2), a diluent cap value of 19.0 percent O_2 or 1.0 percent CO_2 (as applicable) may be used in the emission calculations.

(c) Correction of measured NO_X concentrations to 15 percent O_2 is not allowed.

(d) If you have installed and certified a NO_X diluent CEMS to meet the requirements of Part 75 of this chapter, states can approve that only quality assured data from the CEMS shall be used to identify excess emissions under this subpart. Periods where the missing data substitution procedures in Subpart D of Part 75 are applied are to be reported as monitor downtime in the excess emissions and monitoring performance report required under §60.7(c).

(e) All required fuel flow rate, steam flow rate, temperature, pressure, and megawatt data must be reduced to hourly averages.

(f) Calculate the hourly average NO_X emission rates, in units of the emission standards under §60.4320, using either ppm for units complying with the concentration limit or the equations 1 (simple cycle turbines) or 2 (combined cycle turbines) listed in §60.4350, paragraph (f).

Avenal Power Center is proposing to monitor the NO_X emissions rates from the turbines with a CEMS. The CEMS system will be used to determine if, and when, any excess NO_X emissions are released to the atmosphere from the turbine exhaust stacks. The CEMS will be operated in accordance with the methods and procedures described above. Therefore, the proposed turbines will be operating in compliance with the requirements of this section. The following condition will ensure continued compliance with the requirements of this section:

- Results of continuous emissions monitoring shall be reduced according to the procedure established in 40 CFR, Part 51, Appendix P, paragraphs 5.0 through 5.3.3, or by other methods deemed equivalent by mutual agreement with the District, the ARB, and the EPA. [District Rule 1080]

<u>Section 60.4355 – Parameter Monitoring Plan:</u>

This section sets forth the requirements for operators that elect to continuously monitor parameters in lieu of installing a CEMS for NO_X emissions. As discussed above, Avenal Power Center is proposing to install CEMS on each of these turbines that will directly measure NO_X emissions. Therefore, the requirements of this section are not applicable and no further discussion is required.

<u>Sections 60.4360, 60.4365 and 60.4370 – Monitoring of Fuel Sulfur Content:</u>

Section 60.4360 states that an operator must monitor the total sulfur content of the fuel being fired in the turbine, except as provided in §60.4365. The sulfur content of the fuel must be determined using total sulfur methods described in §60.4415. Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than half the applicable limit, ASTM D4084, D4810, D5504, or D6228, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see §60.17), which measure the major sulfur compounds, may be used.

Section 60.4365 states that an operator may elect not to monitor the total sulfur content of the fuel combusted in the turbine, if the fuel is demonstrated not to exceed potential sulfur emissions of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for units located in continental areas and 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for units located in noncontinental areas or a continental area that the Administrator determines does not have access to natural gas and that the removal of sulfur compounds would cause more environmental harm than benefit. You must use one of the following sources of information to make the required demonstration:

(a) The fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifying that the maximum total sulfur content for oil use in continental areas is 0.05 weight percent (500 ppmw) or less and 0.4 weight percent (4,000 ppmw) or less for noncontinental areas, the total sulfur content for natural gas use in continental areas is 20 grains of sulfur or less per 100 standard cubic feet and 140 grains of sulfur or less per 100 standard cubic feet for noncontinental areas, has potential sulfur emissions of less than less than 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for continental areas and has potential sulfur emissions of less than less than 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for noncontinental areas; or

(b) Representative fuel sampling data which show that the sulfur content of the fuel does not exceed 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for continental areas or 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for noncontinental areas. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of Appendix D to Part 75 of this chapter is required.

Avenal Power Center is proposing to operate these turbines on natural gas that contains a maximum sulfur content of 1.0 grains/100 scf. Primarily, the natural gas supplier should be able to provide a purchase contract, tariff sheet or transportation contract for the fuel that demonstrates compliance with the natural gas sulfur content limit. However, Avenal Power Center has asked that the option of either using a purchase contract, tariff sheet or transportation contract or actually physically monitoring the sulfur content be incorporated into their permit.

Section 60.4370 states that the frequency of determining the sulfur content of the fuel must be as follows:

(a) *Fuel oil.* For fuel oil, use one of the total sulfur sampling options and the associated sampling frequency described in sections 2.2.3, 2.2.4.1, 2.2.4.2, and 2.2.4.3 of Appendix D to Part 75 of this chapter (*i.e.*, flow proportional sampling, daily sampling, sampling from the unit's storage tank after each addition of fuel to the tank, or sampling each delivery prior to combining it with fuel oil already in the intended storage tank).

(b) *Gaseous fuel.* If you elect not to demonstrate sulfur content using options in §60.4365, and the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel must be determined and recorded once per unit operating day.

(c) *Custom schedules.* Notwithstanding the requirements of paragraph (b) of this section, operators or fuel vendors may develop custom schedules for determination of the total sulfur content of gaseous fuels, based on the design and operation of the affected facility and the characteristics of the fuel supply. Except as provided in paragraphs (c)(1) and (c)(2) of this section, custom schedules shall be substantiated with data and shall be approved by the Administrator before they can be used to comply with the standard in §60.4330.

When actually required to physically monitor the sulfur content in the fuel burned in these turbines, Avenal Power Center is proposing a custom monitoring schedule. The District and EPA have previously approved a custom monitoring schedule of at least one per week. Then, if compliance with the fuel sulfur content limit is demonstrated for eight consecutive weeks, the monitoring frequency shall be at least once every six months. If any six month monitoring period shows an exceedance, weekly monitoring shall resume. Avenal Power Center is proposing to follow this same pre-approved fuel sulfur content monitoring scheme for the turbines. The following condition will ensure continued compliance with the requirements of this section:

- The sulfur content of each fuel source shall be: (i) documented in a valid purchase contract, a supplier certification, a tariff sheet or transportation contract or (ii) monitored within 60 days of the end of the commission period and weekly thereafter. If the sulfur content is demonstrated to be less than 1.0 gr/100 scf for eight consecutive weeks, then the monitoring frequency shall be every six months. If the result of any six month monitoring demonstrates that the fuel does not meet the fuel sulfur content limit, weekly monitoring shall resume. [District Rule 2201 and 40 CFR 60.4360, 60.4365(a) and 60.4370(c)]

Section 60.4380 – Excess NO_X Emissions:

Section 60.4380 establishes reporting requirements for periods of excess emissions and monitor downtime. Paragraph (a) lists requirements for operators choosing to monitor parameters associated with water or steam to fuel ratios. As discussed above, Avenal Power Center is not proposing to monitor parameters associated with water or steam to fuel ratios to predict what the NO_X emissions from the turbines will be. Therefore, the requirements of this paragraph are not applicable and no further discussion is required.

Paragraph (b) states that for turbines using CEM's:

(1) An excess emissions is any unit operating period in which the 4-hour or 30-day rolling average NO_X emission rate exceeds the applicable emission limit in §60.4320. For the purposes of this subpart, a "4-hour rolling average NO_X emission rate" is the arithmetic average of the average NO_X emission rate in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given hour and the three unit operating hour average NO_X emission rates immediately preceding that unit operating hour. Calculate the rolling average if a valid NO_X emission rate is obtained for at least 3 of the 4 hours. For the purposes of this subpart, a "30-day rolling average NO_X emission rate" is the arithmetic average of all hourly NO_X emission data in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given day and the twenty-nine unit operating days immediately preceding that unit operating day. A new 30-day average is calculated each unit operating day as the average of all hourly NO_X emissions rates for the preceding 30 unit operating days if a valid NO_X emission rate is obtained for at least 75 percent of all operating hours.

(2) A period of monitor downtime is any unit operating hour in which the data for any of the following parameters are either missing or invalid: NO_X concentration, CO2 or O_2 concentration, fuel flow rate, steam flow rate, steam temperature, steam pressure, or megawatts. The steam flow rate, steam temperature, and steam pressure are only required if you will use this information for compliance purposes.

(3) For operating periods during which multiple emissions standards apply, the applicable standard is the average of the applicable standards during each hour. For hours with multiple emissions standards, the applicable limit for that hour is determined based on the condition that corresponded to the highest emissions standard.

Paragraph (c) lists requirements for operators who choose to monitor combustion parameters that document proper operation of the NO_X emission controls. Avenal Power Center is not proposing to monitor combustion parameters that document proper operation of the NO_X emission controls. Therefore, the requirements of this paragraph are not applicable and no further discussion is required.

The following condition will ensure continued compliance with the requirements of this section:

- Excess emissions shall be defined as any operating hour in which the 4-hour or 30-day rolling average NO_X concentration exceeds applicable emissions limit and a period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour for either NO_X or O2 (or both). [40 CFR 60.4380(b)(1)]

Section 60.4385 – Excess SO_X Emissions:

Section 60.4385 states that if an operator chooses the option to monitor the sulfur content of the fuel, excess emissions and monitoring downtime are defined as follows:

(a) For samples of gaseous fuel and for oil samples obtained using daily sampling, flow proportional sampling, or sampling from the unit's storage tank, an excess emission occurs each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the combustion turbine exceeds the applicable limit and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit.

(b) If the option to sample each delivery of fuel oil has been selected, you must immediately switch to one of the other oil sampling options (i.e., daily sampling, flow proportional sampling, or sampling from the unit's storage tank) if the sulfur content of a delivery exceeds 0.05 weight percent. You must continue to use one of the other sampling options until all of the oil from the delivery has been combusted, and you must evaluate excess emissions according to paragraph (a) of this section. When all of the fuel from the delivery has been burned, you may resume using the as-delivered sampling option.

(c) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour of a required sample, if invalid results are obtained. The period of monitor downtime ends on the date and hour of the next valid sample.

Avenal Power Center will be following the definitions and procedures specified above for determining periods of excess SO_X emissions. Therefore, the proposed turbines will be operating in compliance with the requirements of this section.

Sections 60.4375, 60.4380, 60.4385 and 60.4395 – Reporting:

These sections establish the reporting requirements for each turbine. These requirements include methods and procedures for submitting reports of monitoring parameters, annual performance tests, excess emissions and periods of monitor downtime. Avenal Power Center is proposing to maintain records and submit reports in accordance with the requirements specified in these sections. Therefore, the proposed turbines will be operating in compliance with the requirements of this section. The following condition will ensure continued compliance with the requirements of this section:

- The owner or operator shall submit a written report of CEM operations for each calendar quarter to the APCO. The report is due on the 30th day following the end of the calendar quarter and shall include the following: Time intervals, data and magnitude of excess NO_X emissions, nature and the cause of excess (if known), corrective actions taken and preventative measures adopted; Averaging period used for data reporting corresponding to the averaging period specified in the emission test period and used to determine compliance with an emissions standard; Applicable time and date of each period during which the CEM was inoperative (monitor downtime), except for zero and span checks, and the nature of system repairs and adjustments; A negative declaration when no excess emissions occurred. [District Rule 1080 and 40 CFR 60.4375(a) and 60.4395]

Section 60.4400 – NO_X Performance Testing:

Section 60.4400, paragraph (a) states that an operator must conduct an initial performance test, as required in §60.8. Susequent NO_X performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test).

Paragraphs (1), (2) and (3) set fourth the requirements for the methods that are to be used during source testing.

Avenal Power Center will be required to source test the exhaust of these turbines within 120 days of initial startup and at least once every 12 months thereafter. They will be required to source test in accordance with the methods and procedures specified in paragraphs (1), (2), and (3). Therefore, the proposed turbines will be operating in compliance with the requirements of this section. The following conditions will ensure continued compliance with the requirements of this section:

- Source testing to determine compliance with the NOx, CO and VOC emission rates (lb/hr and ppmvd @ 15% O_2), NH3 emission rate (ppmvd @ 15% O_2) and PM_{10} emission rate (lb/hr) shall be conducted at least once every 12 months. [District Rules 1081, 2201 and 4703 and 40 CFR 60.4400(a)]

- The following test methods shall be used: NO_X - EPA Method 7E or 20; CO - EPA Method 10 or 10B; VOC - EPA Method 18 or 25; PM10 - EPA Method 5 (front half and back half) or 201 and 202a; ammonia - BAAQMD ST-1B; and O_2 - EPA Method 3, 3A, or 20. EPA approved alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4703 and 40 CFR 60.4400(1)(i)]

Section 60.4405 – Initial CEMS Relative Accuracy Testing:

Section 60.4405 states that if you elect to install and certify a NO_X-diluent CEMS, then the initial performance test required under §60.8 may be performed in the alternative manner described in paragraphs (a), (b), (c) and (d). Avenal Power Center has not indicated that they would like to perform the initial performance test of the CEMS using the alternative methods described in this section. Therefore, the requirements of this section are not applicable and no further discussion is required.

Section 60.4410 – Parameter Monitoring Ranges:

Section 60.4410 sets fourth requirements for operators that elect to monitor combustion parameters or parameters indicative of proper operation of NO_X emission controls. As discussed above, Avenal Power Center is proposing to install a CEMS system to monitor the NO_X emissions from each of these turbines and is not proposing to monitor combustion parameters or parameters indicative of proper operation. Therefore, the requirements of this section are not applicable and no further discussion is required.

Section 60.4415– SO_X Performance Testing:

Section 60.4415 states that an operator must conduct an initial performance test, as required in §60.8. Subsequent SO_2 performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test). There are three methodologies that you may use to conduct the performance tests.

(1) If you choose to periodically determine the sulfur content of the fuel combusted in the turbine, a representative fuel sample would be collected following ASTM D5287 (incorporated by reference, see §60.17) for natural gas or ASTM D4177 (incorporated by reference, see §60.17) for oil. Alternatively, for oil, you may follow the procedures for manual pipeline sampling in section 14 of ASTM D4057 (incorporated by reference, see §60.17). The fuel analyses of this section may be performed either by you, a service contractor retained by you, the fuel vendor, or any other qualified agency. Analyze the samples for the total sulfur content of the fuel using:

(i) For liquid fuels, ASTM D129, or alternatively D1266, D1552, D2622, D4294, or D5453 (all of which are incorporated by reference, see §60.17); or

(ii) For gaseous fuels, ASTM D1072, or alternatively D3246, D4084, D4468, D4810, D6228, D6667, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see §60.17).

Avenal Power Center is proposing to periodically determine the sulfur content of the fuel combusted in each of these turbines when valid purchase contracts, tariff sheets or transportation contract is not available. The sulfur content will be determined using the methods specified above. Therefore, the proposed turbines will be operating in compliance with the requirements of this section. The following condition will ensure continued compliance with the requirements of this section:

- Fuel sulfur content shall be monitored using one of the following methods: ASTM Methods D1072, D3246, D4084, D4468, D4810, D6228, D6667 or Gas Processors Association Standard 2377. [40 CFR 60.4415(a)(1)(i)]

Methodologies (2) and (3) are applicable to operators that elect to measure the SO_2 concentration in the exhaust stream. Avenal Power Center is not proposing to measure the SO_2 in the exhaust stream of the turbines. Therefore, the requirements of these methodologies are not applicable and no further discussion is required.

<u>Conclusion:</u>

Conditions will be incorporated into these permits in order to ensure compliance with each applicable section of this subpart. Therefore, compliance with the requirements of Subpart KKKK is expected and no further discussion is required.

Rule 4002 National Emissions Standards for Hazardous Air Pollutants (NESHAP)

Pursuant to Section 2.0, "*All sources of hazardous air pollution shall comply with the standards, criteria, and requirements set forth therein;*" therefore, the requirements of this rule applies to the Avenal Power Center. However, there are no applicable requirements for a non-major HAPs source. As discussed above, Avenal Power Center is not a major HAP source; therefore, no actions are necessary to show compliance with this rule.

Rule 4101 Visible Emissions

Per Section 5.0, no person shall discharge into the atmosphere emissions of any air contaminant aggregating more than 3 minutes in any hour which is as dark as or darker than Ringelmann 1 (or 20% opacity).

i. C-3953-10-0 and C-3953-11-0 (Turbines)

The following condition will be listed on the ATC to ensure compliance:

- {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

ii. C-3953-12-0 (Boiler)

Based on past experiences with natural gas-fired boilers, no visible emissions are expected to be as dark as or darker than Ringelmann 1 (or 20% opacity). The following condition will be placed on the ATC to assure compliance with this rule.

- {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

iii. C-3953-13-0 (Diesel IC engine powering fire water pump)

The following condition will be listed on the ATC to ensure compliance:

- {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

iv. C-3953-14-0 (Natural gas IC engine electrical generator)

The following condition will be listed on the ATC to ensure compliance:

- {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

Rule 4102 Nuisance

Section 4.0 prohibits discharge of air contaminants which could cause injury, detriment, nuisance or annoyance to the public. Public nuisance conditions are not expected as a result of these operations, provided the equipment is well maintained as required by permit conditions. Therefore, the following condition will be added to the permit to assure compliance with this rule.

- {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

A. California Health & Safety Code 41700 (Health Risk Analysis)

A Health Risk Assessment (HRA) is required for any increase in hourly or annual emissions of hazardous air pollutants (HAPs). HAPs are limited to substances included on the list in CH&SC 44321 and that have an OEHHA approved health risk value. The installation of the permit units for the power plant results in increases in emissions of HAPs.

A health risk screening assessment was performed for the proposed project. The acute and chronic hazard indices were less than 1.0 and the cancer risk was less than one in a million. Under the District's risk management policy, Policy APR 1905, TBACT is not required for any proposed emissions unit as shown in the table below:

Screen HRA Summary				
	Acute Hazard Index	Chronic Hazard Index	70 yr Cancer Risk	T-BACT Required?
C-3953-10-0 (Turbine #1)	0.0	0.0	0.02	No
C-3953-11-0 (Turbine #2)	0.0	0.0	0.02	No
C-3953-12-0 (Auxiliary Boiler)	0.0	0.0	0.01	No
C-3953-13-0 (Diesel-Fired IC Engine Fire Pump)	N/A*	N/A*	0.01	No
C-3953-14-0 (NG-Fired IC Engine Generator)	0.2	0.0	0.0	No

* Acute and Chronic Hazard Indices were not calculated since there is not a risk factor or the risk factor is so low that it has been determined to be insignificant for this type of unit.

B. Discussion of Toxics BACT (TBACT)

TBACT is triggered if the cancer risk exceeds one in one million and if either the chronic or acute hazard index exceeds 1. The results of the health risk assessment show that none of the TBACT thresholds are exceeded. TBACT is not triggered.

Rule 4201 Particulate Matter Concentration

Section 3.1 prohibits discharge of dust, fumes, or total particulate matter into the atmosphere from any single source operation in excess of 0.1 grain per dry standard cubic foot.

i. C-3953-10-0 and –11-0 (Turbines)

PM Conc. (gr/scf) = (PM emission rate) x (7000 gr/lb)

PM_{10} emission rate = 11.78 lb/hr. Assuming 100% of PM is PM_{10}
Exhaust Gas Flow = 1,071,653 dscfm

PM Conc. (gr/scf)=[(11.78 lb/hr) $*$ (7,000 gr/lb)] $\div$ [(1,071,653 ft^3/min) $*$ (60 min/hr)]
PM Conc. = 0.0012 gr/scf

Calculated emissions are well below the allowable emissions level. It can be assumed that emissions from all these turbines will not exceed the allowable 0.1 gr/scf. Therefore, compliance with Rule 4201 is expected.

- {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

ii. C-3953-12-0 (Boiler)

Section 3.1 prohibits discharge of dust, fumes, or total particulate matter into the atmosphere from any single source operation in excess of 0.1 grain per dry standard cubic foot.

F-Factor for NG: 8,578 dscf/MMBtu at 60 °F
PM10 Emission Factor: 0.005 lb-PM10/MMBtu
Percentage of PM as PM10 in Exhaust: 100%
Exhaust Oxygen (O_2) Concentration: 3%

Excess Air Correction to F Factor = $\dfrac{20.9}{(20.9 - 3)} = 1.17$

$$GL = \left(\frac{0.005\ lb-PM}{MMBtu} \times \frac{7{,}000\,grain}{lb-PM}\right) / \left(\frac{8{,}578\ ft^3}{MMBtu} \times 1.17\right)$$

$$GL = 0.0035\ grain/dscf < 0.1\,grain/dscf$$

Therefore, compliance with District Rule 4201 requirements is expected and a permit condition will be listed on the permit as follows:

- {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

iii. C-3953-13-0 (Diesel IC engine fire pump)

Particulate matter emissions from the engine will be less than or equal to the rule limit of 0.1 grain per cubic foot of gas at dry standard conditions as shown by the following:

$$0.059\ \frac{g-PM_{10}}{bhp-hr} \times \frac{1g-PM}{0.96g-PM_{10}} \times \frac{1\,bhp-hr}{2{,}542.5\,Btu} \times \frac{10^6\,Btu}{9{,}051\,dscf} \times \frac{0.35\,Btu_{out}}{1\,Btu_{in}} \times \frac{15.43\,grain}{g} = 0.014\ \frac{grain-PM}{dscf}$$

Since 0.014 grain-PM/dscf is $\leq$ to 0.1 grain per dscf, compliance with Rule 4201 is expected.

Therefore, the following condition will be listed on the ATC to ensure compliance:

- {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

iv. C-3953-14-0 (Natural gas IC engine electrical generator)

Particulate matter emissions from the engine will be less than or equal to the rule limit of 0.1 grain per cubic foot of gas at dry standard conditions as shown by the following:

$$0.034 \frac{g-PM_{10}}{bhp-hr} \times \frac{1g-PM}{0.96g-PM_{10}} \times \frac{1\,bhp-hr}{2{,}542.5\,Btu} \times \frac{10^6\,Btu}{9{,}051\,dscf} \times \frac{0.35\,Btu_{out}}{1\,Btu_{in}} \times \frac{15.43\,grain}{g} = 0.008 \frac{grain-PM}{dscf}$$

Since 0.008 grain-PM/dscf is ≤ to 0.1 grain per dscf, compliance with Rule 4201 is expected.

Therefore, the following condition will be listed on the ATC to ensure compliance:

- {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

Rule 4202 Particulate Matter Emission Rate

Rule 4202 establishes PM emission limits as a function of process weight rate in tons/hr. Gas and liquid fuels are excluded from the definition of process weight. Therefore, Rule 4202 does not apply to any of the permit units in this project, and no further discussion is required.

Rule 4301 *Fuel Burning Equipment*

Rule 4301 limits air contaminant emissions from fuel burning equipment as defined in the rule. Section 3.1 defines fuel burning equipment as "any furnace, boiler, apparatus, stack, and all appurtenances thereto, used in the process of burning fuel for the primary purpose of producing heat or power by indirect heat transfer".

i. C-3953-10-0 and C-3953-11-0 (Turbines)

The CTG's primarily produce power mechanically, i.e. the products of combustion pass across the power turbine blades which causes the turbine shaft to rotate. The turbine shaft is coupled to an electrical generator shaft which is rotated to produce electricity. Because the CTG's primarily produce power by mechanical means, it does not meet the definition of fuel burning equipment. Therefore, Rule 4301 does not apply to the affected equipment and no further discussion is required.

ii. C-3953-12-0 (Boiler)

District Rule 4301 Limits			
Pollutant	NO_2	Total PM	SO_2
ATC #C-3953-12-0 (lb/hr)	0.41	0.19	0.10
Rule Limit (lb/hr)	140	10	200

The above table indicates compliance with the maximum lb/hr emissions in this rule; therefore, continued compliance is expected.

iii. C-3953-13-0 (Diesel IC engine fire pump)

Rule 4301 does not apply to the affected equipment and no further discussion is required.

iv. C-3953-14-0 (Natural gas IC engine electrical generator)

Rule 4301 does not apply to the affected equipment and no further discussion is required.

Rule 4304 Tuning Procedure for Boilers, Steam Generators and Process Heaters

This rule is only applicable to unit C-3953-12-0.

Pursuant to District Rules 4305 and 4306, Section 6.3.1, the boiler is not required to tune since it follows a District approved Alternate Monitoring scheme where the applicable emission limits are periodically monitored. Therefore, the unit is not subject to this rule.

Rule 4305 Boilers Steam Generators and Process Heaters – Phase 2

This rule is only applicable to unit C-3953-12-0.

The unit is natural gas-fired with a maximum heat input of 37.4 MMBtu/hr. Pursuant to Section 2.0 of District Rule 4305, the unit is subject to District Rule 4305, *Boilers, Steam Generators and Process Heaters – Phase 2.*

In addition, the unit is also subject to District Rule 4306, *Boilers, Steam Generators and Process Heaters – Phase 3.*

Since emissions limits of District Rule 4306 and all other requirements are equivalent or more stringent than District Rule 4305 requirements, compliance with District Rule 4306 requirements will satisfy requirements of District Rule 4305.

Conclusion

Therefore, compliance with District Rule 4305 requirements is expected and no further discussion is required.

Rule 4306 Boilers Steam Generators and Process Heaters – Phase 3

This rule is only applicable to unit C-3953-12-0.

The unit is natural gas-fired with a maximum heat input of 37.4 MMBtu/hr. Pursuant to Section 2.0 of District Rule 4306, the unit is subject to District Rule 4306.

Section 5.1, NO_X and CO Emissions Limits

Section 5.1.1 requires that except for units subject to Sections 5.2, NO_X and carbon monoxide (CO) emissions shall not exceed the limits specified in the following table. All ppmv emission limits specified in this section are referenced at dry stack gas conditions and 3.00 percent by volume stack gas oxygen. Emission concentrations shall be corrected to 3.00 percent oxygen in accordance with Section 8.1.

With a maximum heat input of 37.4 MMBtu/hr, the applicable emission limit category is listed in Section 5.1.1, Table 1, Category B, from District Rule 4306.

Rule 4306 Emissions Limits				
Category	Operated on gaseous fuel		Operated on liquid fuel	
	NO_X Limit	CO Limit	NO_X Limit	CO Limit
B. Units with a rated heat input greater than 20.0 MMBtu/hr, except for categories C, D, E, F, G, H, and I units	9 ppmv or 0.011 lb/MMBtu	400 ppmv	40 ppmv or 0.052 lb/MMBtu	400 ppmv

For the unit:

- the proposed NO_x emission factor is 9 ppmvd @ 3% O_2 (0.011 lb/MMBtu), and
- the proposed CO emission factor is 50 ppmvd @ 3% O_2 (0.037 lb/MMBtu).

Therefore, compliance with Section 5.1 of District Rule 4306 is expected.

A permit condition listing the emissions limits will be listed on permit as shown in the DEL section above.

Section 5.2, Low Use

The unit annual heat input will exceed the 9 billion Btu heat input per calendar year criteria limit addressed by this section. Since the unit is not subject to Section 5.2, the requirements of this section do not apply to the unit.

Section 5.3, Startup and Shutdown Provisions

Section 5.3 states that on and after the full compliance schedule specified in Section 7.1, the applicable emission limits of Sections 5.1, 5.2.2 and 5.2.3 shall not apply during start-up or shutdown provided an operator complies with the requirements specified in Sections 5.3.1 through 5.3.4.

According to boiler manufacturers, low NO_X burners will achieve their rated emissions within one to two minutes of initial startup and do not require a special shutdown procedure. Because of the short duration before achieving the rated emission factor following startup, the unit will be subject to the applicable emission limits of Sections 5.1, 5.2.2 and 5.2.3 while in operation.

Section 5.4, Monitoring Provisions

Section 5.4.2 requires that permit units subject to District Rule 4306, Section 5.1 emissions limits shall either install and maintain Continuous Emission Monitoring (CEM) equipment for NO_X, CO and O_2, or install and maintain APCO-approved alternate monitoring.

The facility has proposed to install a CEMS system to satisfy the requirements of this section. The following condition will assure compliance with this section.

- {1832} The exhaust stack shall be equipped with a continuous emissions monitor (CEM) for NOx, CO, and O2. The CEM shall meet the requirements of 40 CFR parts 60 and 75 and shall be capable of monitoring emissions during startups and shutdowns as well as during normal operating conditions. [District Rules 2201 and 1080]

Since the unit is not subject to the requirements listed in Section 5.2.1 or 5.2.2, it is not subject to Section 5.4.3 requirements.

Since the unit is not subject to the requirements of category H (maximum annual heat input between 9 billion and 30 billion Btu/year) listed in Section 5.1.1, it is not subject to Section 5.4.4 requirements.

Section 5.5, Compliance Determination

Section 5.5.1 requires that the operator of any unit shall have the option of complying with either the applicable heat input (lb/MMBtu) emission limits or the concentration (ppmv) emission limits specified in Section 5.1. The emission limits selected to demonstrate compliance shall be specified in the source test proposal pursuant to Rule 1081 (Source Sampling). Therefore, the following condition will be listed on the permit as follows:

- {2976} The source plan shall identify which basis (ppmv or lb/MMBtu) will be used to demonstrate compliance. [District Rules 4305 and 4306]

Section 5.5.2 requires that all emissions measurements shall be made with the unit operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. No determination of compliance shall be established within two hours after a continuous period in which fuel flow to the unit is shut off for 30 minutes or longer, or within 30 minutes after a re-ignition as defined in Section 3.0. Therefore, the following permit condition will be listed on the permit as follows:

- {2972} All emissions measurements shall be made with the unit operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. No determination of compliance shall be established within two hours after a continuous period in which fuel flow to the unit is shut off for 30 minutes or longer, or within 30 minutes after a re-ignition as defined in Section 3.0 of District Rule 4306. [District Rules 4305 and 4306]

Section 5.5.4 requires that for emissions monitoring pursuant to Sections 5.4.2, 5.4.2.1, and 6.3.1 using a portable NO_X analyzer as part of an APCO approved Alternate Emissions Monitoring System, emission readings shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15-consecutive-minute sample reading or by taking at least five (5) readings evenly spaced out over the 15-consecutive-minute period.

Since the applicant does not use a portable analyzer to satisfy the monitoring requirements of District Rule 4306 the requirements of Section 5.5.4 do not apply.

Section 5.5.5 requires that for emissions source testing performed pursuant to Section 6.3.1 for the purpose of determining compliance with an applicable standard or numerical limitation of this rule, the arithmetic average of three (3) 30-consecutive-minute test runs shall apply. If two (2) of three (3) runs are above an applicable limit the test cannot be used to demonstrate compliance with an applicable limit. Therefore, the following permit condition will be listed on the permit as follows:

- {2980} For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit the test cannot be used to demonstrate compliance with an applicable limit. [District Rules 4305 and 4306]

Section 6.1, Recordkeeping

Section 6.1 requires that the records required by Sections 6.1.1 through 6.1.3 shall be maintained for five calendar years and shall be made available to the APCO upon request. Failure to maintain records or information contained in the records that demonstrate noncompliance with the applicable requirements of this rule shall constitute a violation of this rule.

A permit condition will be listed on the permit as follows:

- {2983} All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rules 1070, 4305, and 4306]

Section 6.1.2 requires that the operator of a unit subject to Section 5.2 shall record the amount of fuel use at least on a monthly basis. Since the unit is not subject to the requirements listed in Section 5.2, it is not subject to Section 6.1.2 requirements.

Section 6.1.3 requires that the operator of a unit subject to Section 5.2.1 or 6.3.1 shall maintain records to verify that the required tune-up and the required monitoring of the operational characteristics have been performed. The unit is not subject to Section 6.1.3. Therefore, the requirements of this section do not apply to the unit.

Section 6.2, Test Methods

Section 6.2 identifies the following test methods as District-approved source testing methods for the pollutants listed:

Pollutant	Units	Test Method Required
NO_X	ppmv	EPA Method 7E or ARB Method 100
NO_X	lb/MMBtu	EPA Method 19
CO	ppmv	EPA Method 10 or ARB Method 100
Stack Gas O_2	%	EPA Method 3 or 3A, or ARB Method 100
Stack Gas Velocities	ft/min	EPA Method 2
Stack Gas Moisture Content	%	EPA Method 4

The following permit conditions will be listed on the permit as follows:

- {109} Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]

- {2977} NO_X emissions for source test purposes shall be determined using EPA Method 7E or ARB Method 100 on a ppmv basis, or EPA Method 19 on a heat input basis. [District Rules 4305 and 4306]

- {2978} CO emissions for source test purposes shall be determined using EPA Method 10 or ARB Method 100. [District Rules 4305 and 4306]

- {2979} Stack gas oxygen (O_2) shall be determined using EPA Method 3 or 3A or ARB Method 100. [District Rules 4305 and 4306]

Section 6.3, Compliance Testing

Section 6.3.1 requires that this unit be tested to determine compliance with the applicable requirements of section 5.1 and 5.2.3 not less than once every 12 months. Upon demonstrating compliance on two consecutive compliance source tests, the following source test may be deferred for up to thirty-six months.

The following permit conditions will be listed on the permit as follows:

- {3467} Source testing to measure NOx and CO emissions from this unit while fired on natural gas shall be conducted within 60 days of initial start-up. [District Rules 2201, 4305, and 4306]

- {3466} Source testing to measure NOx and CO emissions from this unit while fired on natural gas shall be conducted at least once every twelve (12) months. After demonstrating compliance on two (2) consecutive annual source tests, the unit shall be tested not less than once every thirty-six (36) months. If the result of the 36-month source test demonstrates that the unit does not meet the applicable emission limits, the source testing frequency shall revert to at least once every twelve (12) months. [District Rules 4305 and 4306]

- {110} The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

Section 6.4, Emission Control Plan (ECP)

Section 6.4.1 requires that the operator of any unit shall submit to the APCO for approval an Emissions Control Plan according to the compliance schedule in Section 7.0 of District Rule 4306.

The proposed modified unit will be in compliance with the emissions limits listed in table 1, Section 5.1 of this rule and with periodic monitoring and source testing requirements. Therefore, this current application for the new proposed unit satisfies the requirements of the Emission Control Plan, as listed in Section 6.4 of District Rule 4306. No further discussion is required.

Section 7.0, Compliance Schedule

Section 7.0 indicates that an operator with multiple units at a stationary source shall comply with this rule in accordance with the schedule specified in Table 2, Section 7.1 of District Rule 4306.

The unit will be in compliance with the emissions limits listed in table 1, Section 5.1 of this rule, and periodic monitoring and source testing as required by District Rule 4306. Therefore, requirements of the compliance schedule, as listed in Section 7.1 of District Rule 4306, are satisfied. No further discussion is required.

Conclusion

Conditions will be incorporated into the permit in order to ensure compliance with each section of this rule, see attached draft permit(s). Therefore, compliance with District Rule 4306 requirements is expected.

Rule 4351 Boilers Steam Generators and Process Heaters – Phase 1

This rule is only applicable to unit C-3953-12.

This rule applies to boilers, steam generators, and process heaters at NO_x Major Sources that are not located west of Interstate 5 in Fresno, Kings, or Kern counties. If applicable, the emission limits, monitoring provisions, and testing requirements of this rule are satisfied when the unit is operated in compliance with Rule 4306. Therefore, compliance with this rule is expected.

Rule 4701 Internal Combustion Engines – Phase 1

This rule is only applicable to units C-3953-13-0 and –14-0.

Pursuant to Section 7.5.2.3 of District Rule 4702, as of June 1, 2006 District Rule 4701 is no longer applicable to diesel-fired emergency standby or emergency IC engines. Therefore, this diesel-fired emergency IC engine will comply with the requirements of District Rule 4702 and no further discussion is required.

Rule 4702 Internal Combustion Engines – Phase 2

This rule is only applicable to units C-3953-13-0 and –14-0.

The purpose of this rule is to limit the emissions of nitrogen oxides (NO_X), carbon monoxide (CO), and volatile organic compounds (VOC) from internal combustion engines.

This rule applies to any internal combustion engine with a rated brake horsepower greater than 50 horsepower.

Pursuant to Section 4.2, except for the requirements of Sections 5.7 and 6.2.3, the requirements of this rule shall not apply to an internal combustion engine that meets the following condition:

1) An emergency standby engine as defined in Section 3.0 of this rule, and provided that it is operated with a nonresettable elapsed operating time meter. In lieu of a nonresettable time meter, the owner of an emergency engine may use an alternative device, method, or technique, in determining operating time provided that the alternative is approved by the APCO. The owner of the engine shall properly maintain and operate the time meter or alternative device in accordance with the manufacturer's instructions.

Section 3.15 defines an "Emergency Standby Engine" as an internal combustion engine which operates as a temporary replacement for primary mechanical or electrical power during an unscheduled outage caused by sudden and reasonably unforeseen natural disasters or sudden and reasonably unforeseen events beyond the control of the operator. An engine shall be considered to be an emergency standby engine if it is used only for the following purposes: (1) periodic maintenance, periodic readiness testing, or readiness testing during and after repair work; (2) unscheduled outages, or to supply power while maintenance is performed or repairs are made to the primary power supply; and (3) if it is limited to operate 100 hours or less per calendar year for non-emergency purposes. An engine shall not be considered to be an emergency standby engine if it is used: (1) to reduce the demand for electrical power when normal electrical power line service has not failed, or (2) to produce power for the utility electrical distribution system, or (3) in conjunction with a voluntary utility demand reduction program or interruptible power contract.

Therefore, unit C-3953-14-0, the emergency standby IC engine powering an electrical generator involved with this project will only have to meet the requirements of Sections 5.7 and 6.2.3 of this Rule.

Pursuant to Section 4.3, except for the requirements of Section 6.2.3, the requirements of this rule shall not apply to an internal combustion engine that meets the following conditions:

1) The engine is operated exclusively to preserve or protect property, human life, or public health during a disaster or state of emergency, such as a fire or flood, and
2) Except for operations associated with Section 4.3.1.1, the engine is limited to operate no more than 100 hours per calendar year as determined by an operational nonresettable elapsed operating time meter, for periodic maintenance, periodic readiness testing, and readiness testing during and after repair work of the engine, and
3) The engine is operated with a nonresettable elapsed operating time meter. In lieu of installing a nonresettable time meter, the owner of an engine may use an alternative device, method, or technique, in determining operating time provided that the alternative is approved by the APCO. The owner of the engine shall properly maintain and operate the time meter or alternative device in accordance with the manufacturer's instructions.

Therefore, unit C-3953-13-0, the emergency IC engine powering a firewater pump involved with this project will only have to meet the requirements of Section 6.2.3 of this Rule.

Section 5.7 of this Rule requires that the owner of an emergency standby engine shall comply with the requirements specified in Section 5.7.2 through Section 5.7.5 below:

1) Properly operate and maintain each engine as recommended by the engine manufacturer or emission control system supplier.

2) Monitor the operational characteristics of each engine as recommended by the engine manufacturer or emission control system supplier.

3) Install and operate a nonresettable elapsed operating time meter. In lieu of installing a nonresettable time meter, the owner of an engine may use an alternative device, method, or technique, in determining operating time provided that the alternative is approved by the APCO and is allowed by Permit-to-Operate or Stationary Equipment Registration condition. The owner of the engine shall properly maintain and operate the time meter or alternative device in accordance with the manufacturer's instructions.

Therefore, the following conditions will be listed on ATC **C-3953-14-0** to ensure compliance:

C-3953-14-0 (Natural Gas IC engine electrical generator)

- This engine shall be operated and maintained in proper operating condition as recommended by the engine manufacturer or emissions control system supplier. [District Rule 4702]
- During periods of operation for maintenance, testing, and required regulatory purposes, the permittee shall monitor the operational characteristics of the engine as recommended by the manufacturer or emission control system supplier (for example: check engine fluid levels, battery, cables and connections; change engine oil and filters; replace engine coolant; and/or other operational characteristics as recommended by the manufacturer or supplier). [District Rule 4702]
- This engine shall be equipped with an operational non-resettable elapsed time meter or other APCO approved alternative. [District Rule 4702 and 17 CCR 93115]
- An emergency situation is an unscheduled electrical power outage caused by sudden and reasonably unforeseen natural disasters or sudden and reasonably unforeseen events beyond the control of the permittee. [District Rule 4702]
- This engine shall not be used to produce power for the electrical distribution system, as part of a voluntary utility demand reduction program, or for an interruptible power contract. [District Rule 4702]
- This engine shall be operated only for testing and maintenance of the engine, required regulatory purposes, and during emergency situations. Operation of the engine for maintenance, testing, and required regulatory purposes shall not exceed 50 hours per calendar year. [District Rule 4702]

Section 6.2.3 requires that an owner claiming an exemption under Section 4.2 or Section 4.3 shall maintain annual operating records. This information shall be retained for at least five years, shall be readily available, and submitted to the APCO upon request and at the end of each calendar year in a manner and form approved by the APCO. Therefore, the following conditions will be listed on ATCs **C-3953-13-0 and –14-0** to ensure compliance:

C-3953-13-0 (Diesel IC engine fire pump)

- {3816} This engine shall be operated only for testing and maintenance of the engine, required regulatory purposes, and during emergency situations. For testing purposes, the engine shall only be operated the number of hours necessary to comply with the testing requirements of the National Fire Protection Association (NFPA) 25 - "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems", 1998 edition. Total hours of operation for all maintenance, testing, and required regulatory purposes shall not exceed 50 hours per calendar year. [District Rule 4702 and 17 CCR 93115]

- {3489} The permittee shall maintain monthly records of emergency and non-emergency operation. Records shall include the number of hours of emergency operation, the date and number of hours of all testing and maintenance operations, and the purpose of the operation (for example: load testing, weekly testing, rolling blackout, general area power outage, etc.). For units with automated testing systems, the operator may, as an alternative to keeping records of actual operation for testing purposes, maintain a readily accessible written record of the automated testing schedule. [District Rule 4702 and 17 CCR 93115]

- {3475} All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rule 4702 and 17 CCR 93115]

In addition, the following condition will be listed on the ATC to ensure compliance:

- {3404} This engine shall be equipped with an operational non-resettable elapsed time meter or other APCO approved alternative. [District Rule 4702]

- {3807} An emergency situation is an unscheduled electrical power outage caused by sudden and reasonably unforeseen natural disasters or sudden and reasonably unforeseen events beyond the control of the permittee. [District Rule 4702]

- {3808} This engine shall not be used to produce power for the electrical distribution system, as part of a voluntary utility demand reduction program, or for an interruptible power contract. [District Rule 4702]

C-3953-14-0 (Natural Gas IC engine electrical generator)

- The permittee shall maintain monthly records of emergency and non-emergency operation. Records shall include the number of hours of emergency operation, the date and number of hours of all testing and maintenance operations, the purpose of the operation (for example: load testing, weekly testing, rolling blackout, general area power outage, etc.) and records of operational characteristics monitoring. For units with automated testing systems, the operator may, as an alternative to keeping records of actual operation for testing purposes, maintain a readily accessible written record of the automated testing schedule. [District Rule 4702]

- All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rule 4702]

Rule 4703 Stationary Gas Turbines

This rule is only applicable to units C-3953-10-0 and -11-0.

Rule 4703 is applicable to stationary gas turbines with a rating greater than 0.3 megawatts. The facility proposes to install two 180 MW gas turbines. Therefore the requirements of this rule apply to the proposed turbines.

Section 5.1 – NO_X Emission Requirements:

Section 5.1.1 (Tier I) of this rule limits the NO_X emissions from stationary gas turbine systems greater than 10 MW, and equipped with Selective Catalytic Reduction (SCR). Since the proposed turbines will meet the more stringent Tier 2 emission equirements in Section 5.1.2, compliance with this section is assured.

Section 5.1.2 (Tier 2) of this rule limits the NO_X emissions from combined cycle, stationary gas turbine systems rated at greater than 10 MW to 5 ppmv @ 15% O_2 (Standard option) and 3 ppmv @ 15% O_2 (Enhanced Option). Section 7.2.1 (Table 7-1) sets a compliance date of April 30, 2004 for the Standard Option and Section 7.2.4 sets a compliance date of April 30, 2008 for the Enhanced Option. As discussed above, the proposed turbines will be limited to 2.0 ppmv @ 15% O_2 (based on a 1-hour average), therefore compliance with this section is expected. The following conditions will ensure continued compliance with the requirements of this section:

- Emission rates from this unit (with duct burner firing), except during startup and shutdown periods, shall not exceed any of the following limits: NOx (as NO2) – 17.20 lb/hr and 2.0 ppmvd @ 15% O2; VOC (as methane) – 5.89 lb/hr and 2.0 ppmvd @ 15% O2; CO – 10.60 lb/hr and 2.0 ppmvd @ 15% O2; PM10 – 11.78 lb/hr; or SOx (as SO2) – 6.65 lb/hr. NOx (as NO2) emission limits are one hour rolling averages. All other emission limits are three hour rolling averages. [District Rules 2201, 4001, and 4703]

- Emission rates from this unit (without duct burner firing), except during startup and shutdown periods, shall not exceed any of the following limits: NOx (as NO2) - 13.55 lb/hr and 2.0 ppmvd @ 15% O2; VOC (as methane) - 3.34 lb/hr and 1.4 ppmvd @ 15% O2; CO – 8.35 lb/hr and 2.0 ppmvd @ 15% O2; PM10 – 8.91 lb/hr; or SOx (as SO2) – 5.23 lb/hr. NOx (as NO2) emission limits are one hour rolling averages. All other emission limits are three hour rolling averages. [District Rules 2201, 4001, and 4703]

Section 5.2 – CO Emission Requirements:

Per Table 5-3 of section 5.2, the CO emissions concentration from the proposed turbines (General Electric Frame 7) must be less than 25 ppmvd @ 15% O_2. Rule 4703 does not include a specific averaging period requirement for demonstrating compliance with the CO emission limit. However, District practice is to have an applicant demonstrate compliance with the CO emissions on a turbine with three hour averaging periods. Therefore, compliance with the CO emission limit shall be demonstrated by an average over a three hour period.

Avenal Power Center is proposing a CO emission concentration limit of 2 ppmvd @ 15% O_2 and will demonstrate compliance using three hour averaging periods. Therefore, the proposed turbines will be operating the turbine in compliance with the CO emission requirements of this rule. The DEL conditions shown in the Section 5.1.2 compliance section will ensure continued compliance with the requirements of this section.

Section 5.3 – Startup and Shutdown Requirements:

This section states that the emission limit requirements of Sections 5.1.1, 5.1.2 or 5.2 shall not apply during startup, shutdown, or a reduced load period provided an operator complies with the requirements specified below:

- The duration of each startup or each shutdown shall not exceed two hours, and the duration of each reduced load period shall not exceed one hour, except as provided below.
- The emission control system shall be in operation and emissions shall be minimized insofar as technologically feasible during startup, shutdown, or a reduced load period.
- An operator may submit an application to allow more than two hours for each startup or each shutdown or more than one hour for each reduced load period provided the operator meets all of the conditions specified in the rule.

Avenal Power Center is proposing to incorporate startup and shutdown provisions into the operating requirements for each of the proposed turbines. They have proposed that the duration of each startup or shutdown event will last no more than six hours per day. Since this proposed duration is longer than what is allowed in Section 5.3.1.1, the facility must meet the requirements of Section 5.3.3.2. Section 5.3.3.2 states that at a minimum, a justification for the increased duration shall include the following:

<u>A clear identification of the control technologies or strategies to be utilized; and</u>

The facility has identified the following control technologies:

- Dry low-NOx combustors in the turbines;
- Oxidation catalyst in the HRSGs;
- SCR in the HRSGs;
- Good combustion practices;
- Upon startup, the ammonia injection upstream of the SCR catalyst will be started as soon as the catalyst and ammonia injection system warm to their minimum operating temperatures specified by the SCR vendor.

<u>A description of what physical conditions prevail during the period that prevent the controls from being effective; and</u>

The combined-cycle equipment startup duration depends on how fast the thick steel walls of the common steam turbine can be warmed to operating temperature without generating stress cracks. Steam developed in the HRSG from the heated turbine exhaust is admitted into the steam turbine at a controlled temperature to heat it as rapidly as possible without causing stress cracking. The steam temperature is controlled by limiting the load on the gas turbine. The allowable rate of temperature increase at the steam turbine is the limiting factor determining how quickly the gas turbines can achieve higher loads. This, in turn, limits how quickly the gas turbine combustors can achieve the lowest emitting operating mode, and this latter step is necessary for the units to be able to comply with the limits of Rule 4703.

<u>A reasonably precise estimate as to when the physical conditions will have reached a state that allows for the effective control of emissions; and</u>

Startup information provided by the turbine and HRSG vendors indicates that for a cold startup, a minimum of four hours is required for the unit to come into compliance with the limits of Rule 4703. Depending on the temperature of the steam turbine at the time the start is initiated, shorter durations may be possible.

<u>A detailed list of activities to be performed during the period and a reasonable explanation for the length of time needed to complete each activity; and</u>

The facility has provided the District with a detailed list of activities to be performed during the period and a reasonable explanation for the length of time needed to complete each activity.

A description of the material process flow rates and system operating parameters, etc., the operator plans to evaluate during the process optimization; and an explanation of how the activities and process flow affect the operation of the emissions control equipment; and

The startup duration depends on the allowable ramp rate of the steam temperature to the steam turbine, which depends on the acceptable rate of increase of the metal temperature of the HRH and HP bowls at the steam turbine inlets. The maximum steam temperature is set by applying an allowable differential above the metal temperature. The differential is determined by the steam turbine supplier, and is imposed by the supplier's control system to avoid damage to the steam turbine from thermal stress. The control system limits gas turbine load to control the steam temperature. Manual override of the gas turbine load limit by the operator reduces the life expectancy of the steam turbine.

In addition, the time prior to initiation of ammonia flow to the SCR system depends on the temperature of the SCR catalyst. The catalyst bed is warmed by the exhaust flow from the gas turbine. The total mass of metal and water in the HRSG tubes, piping, and drums removes heat from the gas turbine exhaust as it warms. This extends the time required to heat the SCR catalyst to the minimum temperature at which ammonia may be injected upstream of the catalyst bed to begin reducing NOx to N_2. The steam turbine and SCR catalyst temperatures are all monitored by the plant control system, and the turbine ramp rate and SCR initiation sequence are governed by the equipment/system manufacturer's recommended procedures.

The basis for the requested additional duration.

The startup curve in Attachment I and the description of activities above demonstrate that the minimum time required for a cold startup of the plant as currently configured is approximately 4 hours. This startup time is contingent upon all of the activities being performed in time to support subsequent activities. Any delay in preparation of the supporting systems will result in a corresponding delay in startup and/or loading of the gas turbines. To be confident that the startup time allowed is adequate and will not be exceeded, one hour is added to the above startup time to account for possible delays.

Since the facility has demonstrated compliance and provided all the information asked for in Section 5.3.3.2, the proposed increase in startup and shutdown emissions is compliant with District Rule 4703. The following conditions will ensure continued compliance with the requirements of this section:

- During start-up and shutdown, CTG exhaust emission rates shall not exceed any of the following limits: NO_X (as NO_2) – 160 lb/hr; CO – 1,000 lb/hr; VOC (as methane) – 16 lb/hr; PM_{10} – 11.78 lb/hr; SO_X (as SO_2) – 6.652 lb/hr; or NH_3 – 32.13 lb/hr. [District Rules 2201 and 4703]

- Startup shall be defined as the period of time during which a unit is brought from a shutdown status to its operating temperature and pressure, including the time required by the unit's emission control system to reach full operations. Shutdown shall be defined as the period of time during which a unit is taken from an operational to a non-operational status by allowing it to cool down from its operating temperature to ambient temperature as the fuel supply to the unit is completely turned off. [District Rules 2201 and 4703]

- The duration of each startup or shutdown shall not exceed six hours. Startup and shutdown emissions shall be counted toward all applicable emission limits. [District Rules 2201 and 4703]

- The emission control systems shall be in operation and emissions shall be minimized insofar as technologically feasible during startup and shutdown. [District Rule 4703]

Section 6.2 - Monitoring and Recordkeeping:

Section 6.2.1 requires the owner to operate and maintain continuous emissions monitoring equipment for NO_X and oxygen, or install and maintain APCO-approved alternate monitoring. As discussed earlier in this evaluation, the applicant operates a Continuous Emissions Monitoring System (CEMS) that monitors the NO_X and oxygen content of the turbine exhaust. Therefore, the requirements of this section have been satisfied. The following condition will ensure continued compliance with the requirements of this section:

- The owner or operator shall install, certify, maintain, operate and quality-assure a Continuous Emission Monitoring System (CEMS) which continuously measures and records the exhaust gas NO_X, CO and O_2 concentrations. Continuous emissions monitor(s) shall be capable of monitoring emissions during normal operating conditions, and during startups and shutdowns~~,~~ provided the CEMS pass the relative accuracy requirement for startups and shutdowns specified herein. If relative accuracy of CEMS cannot be demonstrated during startup conditions, CEMS results during startup and shutdown events shall be replaced with startup emission rates obtained from source testing to determine compliance with emission limits contained in this document. [District Rules 1080 and 4703 and 40 CFR 60.4335(b)(1)]

Section 6.2.2 specifies monitoring requirements for turbines without exhaust-gas NO_X control devices. Each of the proposed turbines will be equipped with an SCR system that is designed to control NO_X emissions. Therefore, the requirements of this section are not applicable and no further discussion is required.

Section 6.2.3 requires that for units 10 MW and greater that operated an average of more than 4,000 hours per year over the last three years before August 18, 1994, the owner or operator shall monitor the exhaust gas NO_X emissions. The proposed turbines have not been installed. Therefore, they were not in operation prior to August 18, 1994 and the requirements of this section are not applicable. No further discussion is required.

Section 6.2.4 requires the facility to maintain all records for a period of five years from the date of data entry and shall make such records available to the APCO upon request. Avenal Power Center will be required to maintain all records for at least five years and make them available to the APCO upon request. Therefore, the proposed turbines will be operating in compliance with the five year recordkeeping requirements of this rule. The following condition will ensure continued compliance with the requirements of this section:

- The owner or operator of a stationary gas turbine system shall maintain all records of required monitoring data and support information for inspection at any time for a period of five years. [District Rules 2201 and 4703]

Section 6.2.5 requires that the owner or operator shall submit to the APCO, before issuance of the Permit to Operate, information correlating the control system operating to the associated measure NO_X output. This information may be used by the APCO to determine compliance when there is no continuous emission monitoring system for NO_X available or when the continuous emissions monitoring system is not operating properly. Avenal Power Center will be required, by permit condition, to submit information correlating the NO_X control system operating parameters to the associated measured NO_X output. Therefore, the proposed turbines will be operating in compliance with the control system operating parameter requirements of this rule. The following condition will ensure continued compliance with the requirements of this section:

- The permittee shall submit to the District information correlating the NO_X control system operating parameters to the associated measured NO_X output. The information must be sufficient to allow the District to determine compliance with the NO_X emission limits of this permit during times that the CEMS is not functioning properly. [District Rule 4703]

Section 6.2.6 requires the facility to maintain a stationary gas turbine system operating log that includes, on a daily basis, the actual local startup and stop time, length and reason for reduced load periods, total hours of operation, and the type and quantity of fuel used. Avenal Power Center will be required to maintain records of each item listed above. Therefore, the proposed turbines will be operating in compliance with the recordkeeping requirements of this rule. The following conditions will ensure continued compliance with the requirements of this section:

- The permittee shall maintain the following records: date and time, duration, and type of any startup, shutdown, or malfunction; performance testing, evaluations, calibrations, checks, adjustments, any period during which a continuous monitoring system or monitoring device was inoperative, and maintenance of any continuous emission monitor. [District Rules 2201 and 4703]

- The permittee shall maintain the following records: hours of operation, fuel consumption (scf/hr and scf/rolling twelve month period), continuous emission monitor measurements, calculated ammonia slip, and calculated NOx mass emission rates (lb/hr and lb/twelve month rolling period). [District Rules 2201 and 4703]

Section 6.2.7 establishes recordkeeping requirements for units that are exempt pursuant to the requirements of Section 4.2. Each of the proposed turbines is subject to the requirements of this rule. Therefore, the requirements of this section are not applicable and no further discussion is required.

Section 6.2.8 requires owners or operators performing startups or shutdowns to keep records of the duration of each startup and shutdown. As discussed in the Section 6.2.6 discussion above for this rule, Avenal Power Center will be required, by permit condition, to maintain records of the date, time and duration or each startup and shutdown. Therefore, the proposed turbines will be operating in compliance with the recordkeeping requirements of this rule.

<u>Sections 6.3 and 6.4 - Compliance Testing:</u>

Section 6.3.1 states that the owner or operator of any stationary gas turbine system subject to the provisions of Section 5.0 of this rule shall provide source test information annually regarding the exhaust gas NO_X and CO concentrations. The turbines operated by Avenal Power Center are subject to the provisions of Section 5.0 of this rule. Therefore, each turbine is required to test annually to demonstrate compliance with the exhaust gas NO_X and CO concentrations. The following condition will ensure continued compliance with the requirements of this section:

- Source testing to determine compliance with the NOx, CO and VOC emission rates (lb/hr and ppmvd @ 15% O_2), NH3 emission rate (ppmvd @ 15% O_2) and PM_{10} emission rate (lb/hr) shall be conducted at least once every 12 months. [District Rules 1081, 2201 and 4703 and 40 CFR 60.4400(a)]

Section 6.3.2 specifies source testing requirements for units operating less than 877 hours per year. As discussed above, the proposed turbines will be allowed to operate in excess of 877 hours per year. Therefore, the requirements of this section are not applicable and no further discussion is required.

Section 6.3.3 states that units with intermittently operated auxiliary burners shall demonstrate compliance with the auxiliary burner both on and off. The following condition will ensure continued compliance with the requirements of this section:

- Compliance with the NO_X and CO emission limits shall be demonstrated with the auxiliary burner both on and off. [District Rule 4703]

Section 6.4 states that the facility must demonstrate compliance annually with the NO_X and CO emission limits using the following test methods, unless otherwise approved by the APCO and EPA:

- Oxides of nitrogen emissions for compliance tests shall be determined by using EPA Method 7E or EPA Method 20.

- Carbon monoxide emissions for compliance tests shall be determined by using EPA Test Methods 10 or 10B.

- Oxygen content of the exhaust gas shall be determined by using EPA Methods 3, 3A, or 20.

- HHV and LHV of gaseous fuels shall be determined by using ASTM D3588-91, ASTM 1826-88, or ASTM 1945-81.

The following condition will ensure continued compliance with the test method requirements of this section:

- The following test methods shall be used: NO_X - EPA Method 7E or 20; CO - EPA Method 10 or 10B; VOC - EPA Method 18 or 25; PM10 - EPA Method 5 (front half and back half) or 201 and 202a; ammonia - BAAQMD ST-1B; and O_2 - EPA Method 3, 3A, or 20. EPA approved alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4703 and 40 CFR 60.4400(1)(i)]

<u>Conclusion:</u>

Conditions will be incorporated into these permits in order to ensure compliance with each applicable section of this rule. Therefore, compliance with the requirements of Rule 4703 is expected and no further discussion is required.

Rule 4801 Sulfur Compounds

Per Section 3.1, a person shall not discharge into the atmosphere sulfur compounds, which would exist as a liquid or gas at standard conditions, exceeding in concentration at the point of discharge: 0.2 % by volume calculated as SO_2 on a dry basis averaged over 15 consecutive minutes:

i. C-3953-10-0 and –11-0 (Turbines)

The sulfur of the natural gas fuel is 1.0 gr/100 dscf.

The ratio of the volume of the SO_x exhaust to the entire exhaust for one MMBtu of fuel combusted is:

Volume of SO_x: $V = \frac{n \cdot R \cdot T}{P}$

Where:

- n = number of moles of SO_x produced per MMBtu of fuel.
- Weight of SO_x as SO_2 is 64 lb/(lb-mol)
- $n = \frac{0.00282\ lb}{MMBtu} \times \frac{1\ (lb - mol)}{64\ lb} = 0.000045\ (lb - mol)$
- $R = \frac{0.7302\, ft^3 \cdot atm}{(lb - mol)°R}$
- T = 500 °R
- P = 1 atm

Thus, volume of SO_X per MMBtu is:

$$V = \frac{n \cdot R \cdot T}{P}$$

$$V = \frac{0.000045\ (lb - mol) \cdot \frac{0.7302\ ft^3 \cdot atm}{(lb - mol)\ °R} \cdot 500\ °R}{1\ atm}$$

$$V = 0.016\ ft^3$$

Since the total volume of exhaust per MMBtu is 8,578 scf, the ratio of SO_X volume to exhaust volume is

$$= \frac{0.016}{8{,}578} = 0.0000019 = 1.9\ ppmv = 0.00019\%\ by\ volume$$

1.9 ppmv ≤ 2000 ppmv, therefore the turbines, the boiler, and the gas engine are expected to comply with Rule 4801.

ii. C-3953-12-0 (Boiler)

Using the ideal gas equation and the emission factors presented in Section VII, the sulfur compound emissions are calculated as follows:

$$\text{Volume } SO_2 = \frac{n\ RT}{P}$$

With:

N = moles SO_2
T (Standard Temperature) = 60°F = 520°R
P (Standard Pressure) = 14.7 psi
R (Universal Gas Constant) = $\frac{10.73\,\text{psi}\cdot\text{ft}^3}{\text{lb}\cdot\text{mol}\cdot{}^\circ\text{R}}$

$$\frac{0.00282\,lb-SOx}{MMBtu}\times\frac{MMBtu}{8{,}578\,dscf}\times\frac{1\,lb\cdot mol}{64\,lb}\times\frac{10.73\,psi\cdot ft^3}{lb\cdot mol\cdot{}^\circ R}\times\frac{520^\circ R}{14.7\,psi}\times\frac{1{,}000{,}000\cdot parts}{million}=1.97\frac{parts}{million}$$

$SulfurConcentration = 1.97\frac{parts}{million}$ < 2,000 ppmv (or 0.2%)

Therefore, compliance with District Rule 4801 requirements is expected.

iii. C-3953-13-0 (Diesel IC engine powering a fire water pump)

Using the ideal gas equation, the sulfur compound emissions are calculated as follows:

Volume SO_2 = (n x R x T) ÷ P
n = moles SO_2
T (standard temperature) = 60 °F or 520 °R
R (universal gas constant) = $\frac{10.73\,\text{psi}\cdot\text{ft}^3}{\text{lb}\cdot\text{mol}\cdot{}^\circ\text{R}}$

$$\frac{0.000015\,lb-S}{lb-fuel}\times\frac{7.1\,\text{lb}}{\text{gal}}\times\frac{64\,\text{lb}-SO_2}{32\,\text{lb}-S}\times\frac{1\,\text{MMBtu}}{9{,}051\,\text{scf}}\times\frac{1\,\text{gal}}{0.137\,\text{MMBtu}}\times\frac{\text{lb}-\text{mol}}{64\,\text{lb}-SO_2}\times\frac{10.73\,\text{psi}-\text{ft}^3}{\text{lb}-\text{mol}-{}^\circ\text{R}}\times\frac{520^\circ\text{R}}{14.7\,\text{psi}}\times 1{,}000{,}000 = 1.0\ \text{ppmv}$$

Since 1.0 ppmv is ≤ 2,000 ppmv, this engine is expected to comply with Rule 4801. Therefore, the following condition (previously proposed in this engineering evaluation) will be listed on the ATC to ensure compliance:

- {3395} Only CARB certified diesel fuel containing not more than 0.0015% sulfur by weight is to be used. [District Rules 2201 and 4801 and 17 CCR 93115]

iv. C-3953-14-0 (Natural gas IC engine powering an electrical generator)

Volume SO_2 = (n x R x T) ÷ P
n = moles SO_2
T (standard temperature) = 60 °F or 520 °R
R (universal gas constant) = $\frac{10.73\,\text{psi}\cdot\text{ft}^3}{\text{lb}\cdot\text{mol}\cdot{}^\circ\text{R}}$

$$2.85 \quad \frac{lb-S}{MMscf-gas} \times \frac{1\,scf-gas}{1{,}000\,Btu} \times \frac{1\,MMBtu}{8{,}578\,scf} \times \frac{1\,lb-mol}{64\,lb-S} \times \frac{10.73\,psi-ft^3}{lb-mol-{}^\circ R} \times \frac{520^\circ R}{14.7\,psi} \times 1{,}000{,}000 = \quad 1.97 \quad \text{ppmv}$$

Since 1.97 ppmv is ≤ 2,000 ppmv, this engine is expected to comply with Rule 4801. Therefore, the following condition (previously proposed in this engineering evaluation) will be listed on the ATC to ensure compliance:

- {3491} This IC engine shall be fired on Public Utility Commission (PUC) regulated natural gas only. [District Rules 2201 and 4801]

District Rule 8011 General Requirements
District Rule 8021 Construction, Demolition, Excavation, Extraction And Other Earthmoving Activities
District Rule 8031 Bulk Materials
District Rule 8041 Carryout And Trackout
District Rule 8051 Open Areas
District Rule 8061 Paved And Unpaved Roads
District Rule 8071 Unpaved Vehicle/Equipment Traffic Areas
District Rule 8081 Agricultural Sources

The construction of this new facility will involve excavation, extraction, construction, demolition, outdoor storage piles, paved and unpaved roads.

The regulations from the 8000 Series District Rules contain requirements for the control of fugitive dust. These requirements apply to various sources, including construction, demolition, excavation, extraction, mining activities, outdoor storage piles, paved and unpaved roads. Compliance with these regulations will be required by the following permit conditions, which will be listed on each permit as follows:

- Disturbances of soil related to any construction, demolition, excavation, extraction, or other earthmoving activities shall comply with the requirements for fugitive dust control in District Rule 8021 unless specifically exempted under Section 4.0 of Rule 8021 or Rule 8011. [District Rules 8011 and 8021]

- An owner/operator shall submit a Dust Control Plan to the APCO prior to the start of any construction activity on any site that will include 10 acres or more of disturbed surface area for residential developments, or 5 acres or more of disturbed surface area for non-residential development, or will include moving, depositing, or relocating more than 2,500 cubic yards per day of bulk materials on at least three days. [District Rules 8011 and 8021]

- An owner/operator shall prevent or cleanup any carryout or trackout in accordance with the requirements of District Rule 8041 Section 5.0, unless specifically exempted under Section 4.0 of Rule 8041 (8/19/04) or Rule 8011(8/19/04). [District Rules 8011 and 8021]

- Whenever open areas are disturbed, or vehicles are used in open areas, the facility shall comply with the requirements of Section 5.0 of District Rule 8051, unless specifically exempted under Section 4.0 of Rule 8051 or Rule 8011. [District Rules 8011 and 8051]

- Any paved road or unpaved road shall comply with the requirements of District Rule 8061 unless specifically exempted under Section 4.0 of Rule 8061 or Rule 8011. [District Rules 8011 and 8061]

- Water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure shall be applied to unpaved vehicle travel areas as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

- Where dusting materials are allowed to accumulate on paved surfaces, the accumulation shall be removed daily or water and/or chemical/organic dust stabilizers/suppressants shall be applied to the paved surface as required to maintain continuous compliance with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011 and limit Visible Dust Emissions (VDE) to 20% opacity. [District Rule 8011 and 8071]

- On each day that 50 or more Vehicle Daily Trips or 25 or more Vehicle Daily Trips with 3 axles or more will occur on an unpaved vehicle/equipment traffic area, permittee shall apply water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

- Whenever any portion of the site becomes inactive, Permittee shall restrict access and periodically stabilize any disturbed surface to comply with the conditions for a stabilized surface as defined in Section 3.58 of District Rule 8011. [District Rules 8011 and 8071]

- Records and other supporting documentation shall be maintained as required to demonstrate compliance with the requirements of the rules under Regulation VIII only for those days that a control measure was implemented. Such records shall include the type of control measure(s) used, the location and extent of coverage, and the date, amount, and frequency of application of dust suppressant, manufacturer's dust suppressant product information sheet that identifies the name of the dust suppressant and application instructions. Records shall be kept for one year following project completion that results in the termination of all dust generating activities. [District Rules 8011, 8031, and 8071]

California Environmental Quality Act (CEQA)

The District determined that the California Energy Commission (CEC) is the public agency having principal responsibility for approving the project, therefore establishing the CEC as the Lead Agency (CEQA Guidelines §15051(b). The District is a Responsible Agency for the project because of its discretionary approval power over the project via its Permits Rule (Rule 2010) and New Source Review Rule (Rule 2201), (CEQA Guidelines §15381). The District's engineering evaluation of the project (this document) demonstrates that compliance with District rules and permit conditions would reduce Stationary Source emissions from the project to levels below the District's significance thresholds for criteria pollutants. The District has determined that no additional findings are required (CEQA Guidelines §15096(h)).

California Health & Safety Code, Section 42301.6 (School Notice)

As discussed in Section III of this evaluation, this site is not located within 1,000 feet of a school. Therefore, pursuant to California Health and Safety Code 42301.6, a school notice is not required.

California Health & Safety Code, Section 44300 (Air Toxic "Hot Spots")

Section 44300 of the California Health and Safety Code requires submittal of an air toxics "Hot Spot" information and assessment report for sources with criteria pollutant emissions greater than 10 tons per year. However, Section 44344.5 (b) states that a new facility shall not be required to submit such a report if all of the following conditions are met:

1. The facility is subject to a district permit program established pursuant to Section 42300.
2. The district conducts an assessment of the potential emissions or their associated risks, and finds that the emissions will not result in a significant risk.
3. The district issues a permit authorizing construction or operation of the new facility.

A health risk screening assessment was performed for the proposed project. The acute and chronic hazard indices are less than 1.0 and the cancer risk is less than ten (10) in a million, which are the thresholds of significance for toxic air contaminants. This project qualifies for exemption per the above exemption criteria.

Title 13 California Code of Regulations (CCR), Section 2423 – Exhaust Emission Standards and Test Procedures, Off-Road Compression-Ignition Engines and Equipment (Required by Title 17 CCR, Section 93115 for New Emergency Diesel IC Engines)

The requirements of this section are only applicable to C-3953-13-0.

<u>Particulate Matter and VOC + NO_X, and CO Exhaust Emissions Standards:</u>

This regulation stipulates that off-road compression-ignition engines shall not exceed the following applicable emissions standards.

Title 13 CCR, Section 2423 lists a diesel particulate emission standard of 0.15 g/bhp-hr (with 1.341 bhp/kW, equivalent to 0.20 g/kW-hr) for 2003 - 2005 model year engines with maximum power ratings of 174.3 - 301.6 bhp (equivalent to 130 - 225 kW). The PM standards given in Title 13 CCR, Section 2423 are less stringent than the PM standards given in Title 17 CCR, Section 93115 (ATCM), thus the ATCM standards are the required standards and will be discussed in the following section.

Title 17 CCR, Section 93115, (e)(2)(A)(3)(b) stipulates that new stationary emergency diesel-fueled CI engines (> 50 bhp) must meet the VOC + NO_X, and CO standards for off-road engines of the same model year and maximum rated power as specified in the Off-Road Compression-Ignition Engine Standards (Title 13 CCR, Section 2423) or the Tier 1 standards for an off-road engine if no standards have been established for an off-road engine of the same model year and maximum rated power.

In addition, Title 17 CCR, Section 93115, (e)(2)(A)(4)(a)(II) allows new direct-drive emergency fire pump engines to meet the Tier 2 emission standards specified in the Off-Road Compression Ignition Engine Standards for off-road engines with the same maximum rated power (title 13 CCR, section 2423) until three years after the date the Tier 3 standards are applicable for off-road engines with the same maximum rated power. At that time, new direct-drive emergency diesel-fueled fire-pump engines (>50 bhp) are required to meet the Tier 3 emission standards, until three years after the date the Tier 4 standards are applicable for off-road engines with the same maximum rated power. At that time, new direct-drive emergency diesel-fueled fire-pump engines (>50 bhp) are required to meet the Tier 4 emission standards; and not operate more than the number of hours necessary to comply with the testing requirements of the National Fire Protection Association (NFPA) 25 – "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems," 1998 edition, which is incorporated herein by reference. In addition, this subsection does not limit engine operation for emergency use and for emission testing to show compliance with (e)(2)(A)4. For this project the proposed emergency diesel IC engine will be used to power a firewater pump and is therefore allowed to meet the Tier 2 emission standards specified in the Off-Road Compression Ignition Engine Standards for off-road engines three years after the applicable dates specified. This additional three-year allowance is reflected in the following table.

The engine involved with this project is a certified 2007 model engine. The following table compares the requirements of Title 13 CCR, Section 2423 to the emissions factors for the 288 bhp Cummins Model #CFP83-F40 diesel-fired emergency IC engine as given by the manufacturer (for NO_X + VOC and PM emissions).

Requirements of Title 13 CCR, Section 2423							
Source	Maximum Rated Power	Model Year	NO_X	VOC	NO_X + VOC	CO	PM
Title 13 CCR, §2423	174.3 – 301.6 bhp (130 - 225 kW)	1996-2002 (Tier 1)	6.9 g/bhp-hr (9.2 g/kW-hr)	1.0 g/bhp-hr (1.3 g/kW-hr)	--	8.5 g/bhp-hr (11.4 g/kW-hr)	0.40 g/bhp-hr (0.54 g/kW-hr)
Title 13 CCR, §2423	**174.3 – 301.6 bhp (130 - 225 kW)**	**2003-2005, extended to 2008 (Tier 2)**	--	--	**4.9 g/bhp-hr (6.6 g/kW-hr)**	**2.6 g/bhp-hr (3.5 g/kW-hr)**	**0.15 g/bhp-hr (0.20 g/kW-hr)**
Title 13 CCR, §2423	174.3 – 301.6 bhp (130 - 225 kW)	2006 and later, extended to 2009 (Tier 3)	--	--	3.0 g/bhp-hr (4.0 g/kW-hr)	2.6 g/bhp-hr (3.5 g/kW-hr)	0.15 g/bhp-hr (0.20 g/kW-hr)
Cummins, Model #CFP83-F40	288 bhp	2007	--	--	3.8g/bhp-hr (5.1 g/kW-hr)	0.447 g/bhp-hr (0.60 g/kW-hr)	0.059 g/bhp-hr (0.079 g/kW-hr)
Meets Standard?			N/A	N/A	Yes	Yes	Yes

As presented in the table above, the proposed engine will satisfy the requirements of this section and compliance is expected.

The engine manufacturer's data and/or CARB/EPA engine certification for this engine lists a NO_X emissions factor of 3.4 g/bhp-hr, a VOC emissions factor of 0.38 g/bhp-hr, a NO_X + VOC emission factor of 3.8 g/bhp-hr, a CO emission factor of 0.447 g/bhp-hr, and a PM_{10} emissions factor of 0.059 g/bhp-hr, all of which satisfy the requirements of 13 CCR, Section 2423. Therefore, the following conditions (previously proposed in this engineering evaluation) will be listed on the ATC to ensure compliance:

- Emissions from this IC engine shall not exceed any of the following limits: 3.4 g-NOx/bhp-hr, 0.447 g-CO/bhp-hr, or 0.38 g-VOC/bhp-hr. [District Rule 2201 and 13 CCR 2423 and 17 CCR 93115]

- Emissions from this IC engine shall not exceed 0.059 g-PM10/bhp-hr based on USEPA certification using ISO 8178 test procedure. [District Rules 2201 and 4102 and 13 CCR 2423 and 17 CCR 93115]

<u>Right of the District to Establish More Stringent Standards:</u>

This regulation also stipulates that the District:

1. May establish more stringent diesel PM, NO_X + VOC, VOC, NO_X, and CO emission rate standards; and
2. May establish more stringent limits on hours of maintenance and testing on a site-specific basis; and
3. Shall determine an appropriate limit on the number of hours of operation for demonstrating compliance with other District rules and initial start-up testing

The District has not established more stringent standards at this time. Therefore, the standards previously established in this Section will be utilized.

Title 17 California Code of Regulations (CCR), Section 93115 - Airborne Toxic Control Measure (ATCM) for Stationary Compression-Ignition (CI) Engines

The requirements of this section are only applicable to C-3953-13-0.

Emergency Operating Requirements:

This regulation stipulates that no owner or operator shall operate any new or in-use stationary diesel-fueled compression ignition (CI) emergency standby engine, in response to the notification of an impending rotating outage, unless specific criteria are met.

This section applies to emergency standby IC engines that are permitted to operate during non-emergency conditions for the purpose of providing electrical power. However, District Rule 4702 states that emergency standby IC engines may only be operated during non-emergency conditions for the purposes of maintenance and testing. Therefore, this section does not apply and no further discussion is required.

Fuel and Fuel Additive Requirements:

This regulation also stipulates that as of January 1, 2006 an owner or operator of a new or in-use stationary diesel-fueled CI emergency standby engine shall fuel the engine with CARB Diesel Fuel.

Since the engine involved with this project is a new or in-use stationary diesel-fueled CI emergency standby engine, these fuel requirements are applicable. Therefore, the following condition (previously proposed in this engineering evaluation) will be listed on the ATC to ensure compliance:

- {3395} Only CARB certified diesel fuel containing not more than 0.0015% sulfur by weight is to be used. [District Rules 2201 and 4801 and 17 CCR 93115]

At-School and Near-School Provisions:

This regulation stipulates that no owner or operator shall operate a new stationary emergency diesel-fueled CI engine, with a PM_{10} emissions factor > than 0.01 g/bhp-hr, for non-emergency use, including maintenance and testing, during the following periods:

1. Whenever there is a school sponsored activity, if the engine is located on school grounds, and
2. Between 7:30 a.m. and 3:30 p.m. on days when school is in session, if the engine is located within 500 feet of school grounds.

The District has verified that the engine is not located within 500 feet of a K-12 school. Therefore, conditions prohibiting non-emergency usage of the engine during school hours will not be placed on the permit.

Recordkeeping Requirements:

This regulation stipulates that as of January 1, 2005, each owner or operator of an emergency diesel-fueled CI engine shall keep a monthly log of usage that shall list and document the nature of use for each of the following:

a. Emergency use hours of operation;
b. Maintenance and testing hours of operation;
c. Hours of operation for emission testing;
d. Initial start-up hours; and
e. If applicable, hours of operation to comply with the testing requirements of National Fire Protection Association (NFPA) 25 — "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems," 1998 edition;
f. Hours of operation for all uses other than those specified in sections 'a' through 'd' above; and
g. For in-use emergency diesel-fueled engines, the fuel used. The owner or operator shall document fuel use through the retention of fuel purchase records that account for all fuel used in the engine and all fuel purchased for use in the engine, and, at a minimum, contain the following information for each individual fuel purchase transaction:

    I. Identification of the fuel purchased as either CARB Diesel, or an alternative diesel fuel that meets the requirements of the Verification Procedure, or an alternative fuel, or CARB Diesel fuel used with additives that meet the requirements of the Verification Procedure, or any combination of the above;
    II. Amount of fuel purchased;
    III. Date when the fuel was purchased;
    IV. Signature of owner or operator or representative of owner or operator who received the fuel; and
    V. Signature of fuel provider indicating fuel was delivered.

The proposed new emergency diesel IC engine powering a firewater pump is exempt from the operating hours limitation provided the engine is only operated the amount of hours necessary to satisfy National Fire Protection Association (NFPA) regulations. Therefore, the following conditions (previously proposed in this engineering evaluation) will be listed on the ATC to ensure compliance:

- {3489} The permittee shall maintain monthly records of emergency and non-emergency operation. Records shall include the number of hours of emergency operation, the date and number of hours of all testing and maintenance operations, and the purpose of the operation (for example: load testing, weekly testing, rolling blackout, general area power outage, etc.). For units with automated testing systems, the operator may, as an alternative to keeping records of actual operation for testing purposes, maintain a readily accessible written record of the automated testing schedule. [District Rule 4702 and 17 CCR 93115]

- {3475} All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rule 4702 and 17 CCR 93115]

PM Emissions and Hours of Operation Requirements for New Diesel Engines:

This regulation stipulates that as of January 1, 2005, no person shall operate any new stationary emergency diesel-fueled CI engine that has a rated brake horsepower greater than 50, unless it meets all of the following applicable emission standards and operating requirements.

1. Emits diesel PM at a rate greater than 0.01 g/bhp-hr or less than or equal to 0.15 g/bhp-hr; or
2. Meets the current model year diesel PM standard specified in the Off-Road Compression Ignition Engine Standards for off-road engines with the same maximum rated power (Title 13 CCR, Section 2423), whichever is more stringent; and
3. Does not operate more than 50 hours per year for maintenance and testing purposes. Engine operation is not limited during emergency use and during emissions source testing to show compliance with the ATCM.

The proposed emergency diesel IC engine powering a firewater pump is exempt from the operating hours limitation provided the engine is only operated the amount of hours necessary to satisfy National Fire Protection Association (NFPA) regulations. Therefore, the following conditions (previously proposed in this engineering evaluation) will be listed on the ATC to ensure compliance:

- Emissions from this IC engine shall not exceed 0.059 g-PM10/bhp-hr based on USEPA certification using ISO 8178 test procedure. [District Rules 2201 and 4102 and 13 CCR 2423 and 17 CCR 93115]

- {3816} This engine shall be operated only for testing and maintenance of the engine, required regulatory purposes, and during emergency situations. For testing purposes, the engine shall only be operated the number of hours necessary to comply with the testing requirements of the National Fire Protection Association (NFPA) 25 - "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems", 1998 edition. Total hours of operation for all maintenance, testing, and required regulatory purposes shall not exceed 50 hours per calendar year. [District Rule 4702 and 17 CCR 93115]

IX. RECOMMENDATION:

Compliance with all applicable prohibitory rules and regulations is expected. Issue the Final Determination of Compliance for the facility subject to the conditions presented in Attachment A.

X. BILLING INFORMATION:

Annual Permit Fees			
Permit Number	Fee Schedule	Fee Description	Annual Fee
C-3953-10-0	3020-08B-B	180,000 kW	$12,229.00
C-3953-11-0	3020-08B-B	180,000 kW	$12,229.00
C-3953-12-0	3020-02-H	37.4 MMBtu/hr boiler	$953.00
C-3953-13-0	3020-10-C	288 bhp IC engine	$222.00
C-3953-14-0	3020-10-E	860 bhp IC engine	$557.00